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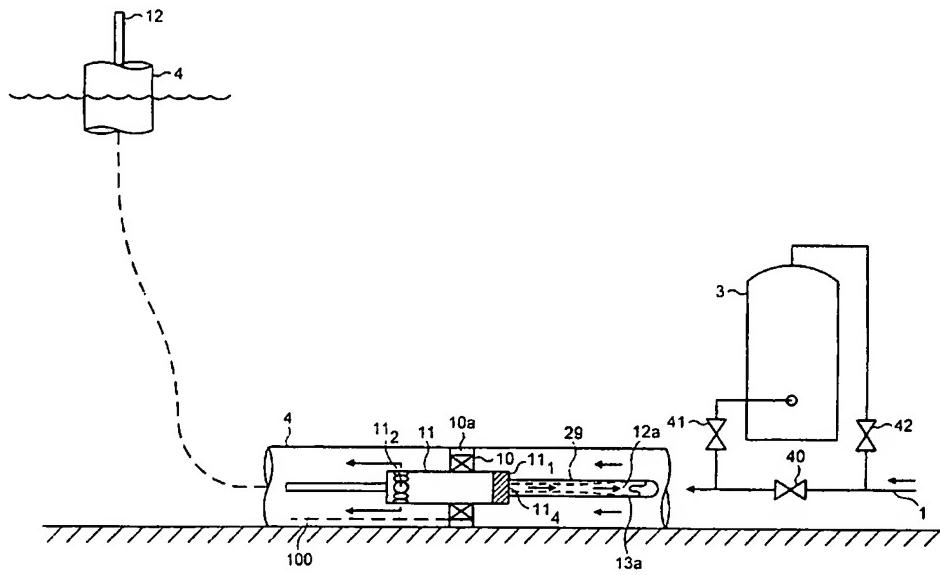
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(57) Abstract: Systems are described for raising production fluid from a source (1) on the seabed comprising a riser (4) having a first, lower, end for connection or connected to the source; a top end support for supporting the riser at or in the vicinity of the sea surface; and an operating device (11) mounted inside the riser (4) for displacement within the riser so that the pump is accessible to an operator for replacement or repair. The operating device (11) may be displaced on a pipe (12) which extends within the riser (4) and to a lower end of which the device (11) is attached. The device (11) may be *inter alia* an electric pump, a hydraulic pump, a gas injector, a heater or a cleaning device.



*For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.*

### RISER WITH RETRIEVABLE INTERNAL SERVICES

This invention relates to riser systems and methods for raising production fluid within the riser system downstream of a subsea source or plurality of sources.

Various techniques are known for raising hydrocarbon production fluids, typically crude oil, gas and water forming a three-phase fluid, from an undersea source on the seabed. Situations where this need exists are the lifting of production fluid from an offshore well to the surface of the sea for separation into different constituents of the production fluids, or from a seabed pipeline coming from a remote well or storage facility. It is known to use a riser for this purpose, the riser extending from the subsea source to the surface of the sea, to an elevated position above the surface of the sea, or to a submerged location at a relatively small distance below the sea surface. The riser may extend generally upwardly or vertically from the subsea source. Alternatively, it may comprise a section (known as a flowline) running along the sea bed from the source, a riser section extending upwardly and a bend section connecting the flowline and riser sections. A subsea drilling system using a tensioned riser is described in US-A-5,474,601. The riser comprises a tubular conductor within which passes a tubing string for conveying oil to the surface from a dummy well.

In many cases, there is initially sufficient pressure at the foot of the riser to overcome the static head of the fluid column in the production riser used to convey the fluid to the surface of the sea. However, with the passage of time, the pressure in the well decreases and may reach a point at which it alone is insufficient. In some cases, the pressure at the riser base may be inadequate from the outset.

Where the pressure is insufficient, gas under pressure is used extensively to provide lift to enable heavy liquids to be raised from the base of the riser. This is common practice in relatively shallow water depths whose riser temperature loss

and pressure reduction are not excessive. However, for deepwater fields (such as 350 metres and beyond) and/or where the reservoir is shallow and cold and the reservoir fluid is inherently gassy or multiphase, gas injection can give rise to operational difficulties such as "slugging" (the formation of "slugs" of liquid separated by gas bubbles), temperature loss during gas expansion, hydrate formation and high fluid velocities in upper regions of the riser due to the reduced fluid head there, which can cause erosion or corrosion of the material of the riser wall.

To address these problems, it is known to use a subsea pump, either a hydraulic-driven submersible pump (HSP) or electrically-driven submersible pump (ESP), which is connected in series with the lower inlet end of the riser to add pressure energy to the production fluids coming from the well, to drive the fluids up the riser to the facility such as top end buoyancy unit, floating production platform or free-standing platform, connected to the upper end of the riser. This offers the advantages not only of lifting fluids that would otherwise not flow but also of reducing the free gas in the hydrocarbon fluids raised to the production facility, the heat loss from the hydrocarbon fluids and the fluid delivery velocity from the riser. It also avoids having to provide a source of high pressure gas and an external gas injection riser.

For a conventional arrangement, the or each subsea pump is positioned externally of and to one side of the riser. However, this siting is undesirable for the following reasons. Firstly, external facilities are required to install the pump near to the seabed, and installation becomes increasingly difficult when working at large sea depths. Secondly, it is time-consuming to repair or replace the pump, since it is not readily accessible. In practice, a maintenance vessel with trained crew has to be called, which travels to the offshore site. Then the crew have to repair or replace the pump by remote handling from the surface, where this is possible. Although this is a time-consuming operation, it is used where possible, but only a limited number of relatively straightforward repairs are feasible in this way. In many cases, the crew have to remotely disconnect the subsea pump and hoist it up in the sea to the maintenance vessel, where it can be repaired or replaced (if a

second redundant pump is not incorporated in the system). The new or repaired pump is then lowered to the sea bed and reconnected to the riser. Whilst the described operations can be done satisfactorily, the time taken can be significant because of working with a pump located under water at a comparatively great depth. The relatively high time factor involved is very undesirable and, when no redundant pump has been incorporated, results in lost production time and therefore lost revenue.

US-A-5,474,601 describes a system in which an electric pump is located near the lower end of a dummy well in the ocean floor. The pump is supplied by a power cable passing up the dummy well, then up the riser to a floating production platform.

US-A-4,705,114 describes a tubular steel riser connected between the ocean surface and a sump embedded in the ocean floor and containing a downhole pump. Concentric pipes pass up the riser to convey liquid and gas separately to a manifold cap at the top of the riser. The installation of the pump is not discussed.

In subsea production systems, the hydrocarbon fluids are transported from one or more seabed located wellheads to the receiving facility located at the sea surface by one or more seabed flowlines and risers. During periods when flow is interrupted and flow ceases, the fluids come to rest and are subjected to pressure generated by the shut-in pressure at the riser top and the hydrostatic head resulting from the liquid held in the riser column. This 'residual pressure' when combined with decreasing temperature as the fluids cool, leads to the formation of solid hydrates which in turn can result in blockage and an inability to produce fluids at restart. To cope with flow interruptions, active conventional methods available to control hydrates include addition of chemicals and active heat addition (electrical or fluid heating tubes). Passive methods include very low heat loss insulation and depressurisation.

The active methods require the continuous availability of chemicals and/or heat. Use of low heat loss insulation extends cool down time, but on its own is not a

sufficient guarantee against blockage if the system cools down completely, unless combined with active methods. Depressurisation below a pressure appropriate to the fluid head at the riser top requires a second access conduit located between the riser tubing head and the wellhead end. This is normally an external pipeline with external crossovers into the hydrocarbon flowline. Such equipment adds to cost and complexity.

In conventional riser systems, transportation of multiphase fluids from a wellhead via a flowline and riser results in the generation of gas and liquid slugs which, when received at the destination facility, can result in process system interruption and damage to pipework and related mechanical components. The severity of slugging becomes worse as the transport distance increases and/or where large elevation changes occur, as are found in deepwater production systems. It is known that retrieval of the produced fluids as separate liquid and gas phases at the destination facility can remove these risks and permit a less complex processing system.

To date, subsea systems aimed at separating the liquid and gas phases downstream of the wellhead have generally included components external to the riser and flowline, requiring the mobilisation of surface vessels to effect their installation/maintenance. Mobilisation of these specialised vessels is expensive, particularly in remote areas where there is minimal local infrastructure. In addition, there is a need to construct and install external mechanical interfaces for this equipment.

US-A-5,285,204 describes a borehole system for operating a downhole generator on a composite coiled tubing string, which is dispensed from a powered spool on the earth's surface.

It is also known from US-A-4,336,415 to employ composite flexible coiled tubing to convey electrical and/or hydraulic power to a drive motor for a downhole pump.

US-A-5,503,014 describes a system using coaxial coiled tubing to supply fluids to a wellbore for performing a drill stem test.

US-A-5,638,904 describes a type of nested coiled tubing in which the individual pipes adopt a helical configuration.

In this specification, the expression "coiled tubing" means tubing which is supplied in coiled form on a drum and dispensed from the drum to pass down a riser.

According to a first aspect of the invention, there is provided a system for raising production fluid from a source on the seabed, comprising:- a riser having an internal passageway for conveying said production fluid and having a first, lower, end for connection to or connected to the source; a top end support for supporting the riser at its second end at or in the vicinity of the sea surface; and an operating device mounted inside the riser for displacement within the riser between a first, operating, position in the riser remote from its second end, and a second, access, position, at the second end of the riser, so that the device is accessible for replacement or repair.

The operating device may be a pump, a heater, a gas injector, or a cutting or cleaning tool. These aspects will be discussed in more detail hereinafter.

It will be appreciated that the riser serves as a transport path for displacement of the operating device initially from the top end support, which is readily accessible to operating crew since it will generally be located in the vicinity of the sea surface (e.g. on board a support vessel or just below the sea surface) or at the sea surface, to the down-riser operating position. This makes the initial installation of the device simple to implement. Similarly, repair or replacement of the device can easily be effected by essentially a reversal of this operation. This avoids having to repair or replace the device in situ, adjacent the sea bed, using a support vessel and highly trained personnel, following a malfunction, and the consequent downtime and loss of revenue through lost production. In addition, the time involved both in the initial installation of the device and also in raising the device

within the riser so that the necessary work can be carried out and then lowering the repaired or new device to its former position can be relatively small.

As already explained, the top end support for the riser may be in the form of a floating support vessel. In another preferred form, it comprises a buoyancy unit tethered to the sea floor and located below the sea surface, to minimise the effect of the surface waves. An ideal depth for the buoyancy unit is substantially 60 metres below the surface, so that the wave action has negligible effect but the buoyancy unit can nevertheless be readily accessed by crew members, for example on an attendant vessel, using conventional handling techniques. The 60 metre depth however is purely an example, and it will be appreciated that the buoyancy unit may be tethered at greater or lesser depths.

Generally, the source of production fluid will be a subsea wellhead, a seabed flowline from a remote subsea wellhead or groups of wellheads, or a seabed flowline from a remote storage facility.

The fluid raising system may further comprise means including a pipe, e.g. coiled tubing, which extends within the riser and to a lower end of which the operating device is attached. The pipe may then serve the dual functions of being itself drivable down and up to lower and raise the device for the required initial installation and subsequent repair or maintenance, and serving as a carrier for the device when it is in its operating position.

As already mentioned, the operating device may be a pump for pumping production fluid from the source.

In one arrangement, the pump is an electric pump and an electric power supply cable for the pump passes through the pipe. Therefore, the space necessarily provided within the pipe is used to accommodate the power supply cable. This contributes to a compact construction for the riser.

In another arrangement, the pump is a hydraulic pump, typically a turbine-driven pump, and the pump displacing means includes a supply pipe which extend within the riser and to the lower end of which the hydraulic pump is attached, the supply pipe being arranged for delivering hydraulic fluid down to the pump, which then discharges it into the production fluid passing up the riser.

In some cases however, especially where only limited mixing of the hydraulic fluid (e.g. pump lubricant) with the production fluid is permissible, a closed hydraulic pressure circuit is needed. Preferably, therefore, the pump is a hydraulic pump attached to lower ends of supply and return pipes extending within the riser, the supply pipe being arranged for delivering hydraulic fluid down to the pump to drive it and the return pipe being arranged for conveying hydraulic fluid from the pump back up the riser.

Although separate supply and return pipes can be provided in the riser running side-by-side, it is preferred, for compactness, that the two pipes form a nested, pipe arrangement, e.g. a collinear arrangement or an arrangement where one or both pipes adopt a helical configuration. Furthermore, a nested pipe arrangement lends itself to being driven into, and withdrawn from, the riser by a single conventional pipe dispensing and retrieving apparatus. Thus, the pump displacing means may include a pipe dispensing and retrieving apparatus on the top end support or an attendant service vessel, such apparatus comprising a rotatable pipe storage device on which the nested pipes are wound, a pipe straightener and drive means for the storage device, selectively operable for straightening a length of the nested pipes and driving them downwardly into the riser to lower the hydraulic pump to said first position and to wind in the nested pipes to raise the pump to said second position.

It is particularly preferred that means are provided for delivering heated hydraulic fluid through the supply pipe for heating production fluid in the riser by heat transfer through the walls of the supply and return pipes. Here either the inner or the outer pipe of a nested pair may form the supply pipe. In this way, the possibility of freeze-ups in adverse operating temperature conditions, or following

temporary shutdown, can be avoided. Furthermore, the hydraulic fluid may then be used not only for driving the down-riser pump, but also for conveying heat to the production fluid, thereby avoiding the need for separate means for providing these two functions. In the prior art, it is known in the industry to specify long cool down time to minimise the risk of freeze-ups, but this necessitates designing a number of components to have high thermal capacity and/or adding inhibitors to prevent hydrate formation, and, in any event, there can be no guarantee of avoiding freeze-ups in this way. Therefore, the measures described represent an advantage over the prior art.

A heater is preferably mounted in the riser between the first end thereof and the pump, the heater being connected to receive heated hydraulic fluid from the supply pipe and to return the fluid to the return pipe. In this way, heat is supplied to the regions in the riser where a freeze-up is most likely to occur. The heater can be a separate component, or it may be provided by intercommunicating bottom end sections of the supply and return pipes.

Depending on operating conditions and the nature of the production fluid to be raised from the sea bed, waxy deposits may form in the riser and need to be removed periodically. Therefore, a pig introducing device may be provided for introducing a pig into the riser at a position below the pump when in said second position. Displacing the pump along the riser from one axial position to another one is also available to provide scraping/cleaning of the riser wall.

In the embodiments described above having a hydraulic pump in the riser, the supply and return pipes serve to deliver hydraulic pressure fluid for driving the pump. However, instead, these pipes may serve solely or principally for supplying heat, to avoid a freeze-up in the riser. If a pump, electric or hydraulic, is needed to raise the production fluid in the riser, it may be positioned externally of the riser and connected in a flowline delivering production fluid to the bottom end of the riser. The pump would then be powered independently of the supply and return pipes.

According to another embodiment of the invention, the operating device may be a heater mounted inside the riser for displacement within the riser between a first, operating, position in the riser remote from its second end, for heating production fluid in the riser, and a second, access position, at the second end of the riser, so that the heater is accessible to an operator for replacement or repair.

Again, the two pipes could be placed side-by-side in the riser, but suitably they can form a nested, preferably collinear or helical, pipe arrangement. The heater displacing means may include a pipe dispensing and retrieving apparatus on the top end support or an attendant service vessel, such apparatus further comprising a rotatable pipe storage device on which the nested pipes are wound, a pipe straightener and drive means for the storage device, selectively operable for straightening a length of the nested pipes and driving them downwardly into the riser to lower said heater to said first position and to wind in the nested pipes to raise the heater to said second position.

In accordance with another embodiment of the invention, the operating device is a gas injector and rigid pipe may comprise a supply pipe for delivering gas under pressure to the gas injector, for providing lift to the production fluid in the riser.

The system may further comprise means for displacing the gas injector in the riser between the operating and access positions.

The gas injector displacing means may include a rigid supply pipe extending downwardly within the riser and carrying said gas injector.

The rigid supply pipe may itself carry the pressure gas or it may carry a separate gas delivery pipe.

It will be appreciated that it is possible to provide a system complying with two or three of the above-defined embodiments at the same time. For example, the rigid supply pipe may be used to supply heating fluid to a heater, but also include a

separate gas supply line used for injecting lift gas into the riser for use with a gas injector.

In another embodiment, a locating device is mounted on the operating device, and is selectively operable for (i) engaging with the inner surface of the riser and (ii) disengaging therefrom so that the operating device can be repositioned in the riser. This permits the down-riser operating device to be moved between one desired position in the riser and another one in the riser or its flowline component merely by disengaging the locating device, displacing the down-riser operating device to the desired new position, and re-engaging the locating device. If desired, the down-riser operating device can be withdrawn through the riser back to the surface for maintenance or repair. Since the locating device is withdrawn from within the riser, there is no need for an attendant vessel or specialised equipment, which would be required in the conventional arrangement where a sub-sea operating device such as a pump is located externally of the riser.

In another embodiment, the operating device is a pump and the locating device is a sealing device which is operable for both engaging and sealing with the inner surface of the riser so that the pump can pump production fluid in the riser from a low pressure side of the sealing device to a high pressure side.

Since the sealing device then not only serves for engaging with the riser inner wall but also for sealing with it, the need to compartmentalise the riser interior into low pressure and high pressure sides (so that the pump can pump from low pressure to high pressure) can be achieved without needing a sealing element separate from the riser wall engaging function.

In a further embodiment, the sealing device comprises a packer mounted on the pump and an inflatable sealing element operable for forming sealing contact with the inner surface of the riser. This is a structurally simple and effective arrangement for achieving the necessary engagement and sealing with the riser wall.

It will be appreciated that a hydraulic pump can more readily cope with sharp bends inside the riser without jamming than an electric pump.

According to another embodiment, in addition to said passageway for carrying the production fluid, a second passageway is provided in the riser for connection to a low pressure region in the vicinity of the upper end of the riser and means are provided for expelling production fluid from the first passageway to said low pressure region, so as to reduce the pressure in the first passageway to a lower value than that existing under interrupted or shutdown conditions, thereby inhibiting formation of solid hydrates in the first passageway.

The production fluid expelling means may comprise a one-way valve providing fluid communication from the first passageway to the second passageway, a source of pressure gas operable for introducing gas under pressure to the first passageway to expel production fluid therefrom through the one-way valve, and means for venting the gas pressure in the first passageway to said region of lower pressure. This is one convenient way of achieving the required pressurised gas introduction and subsequent pressure reduction.

Expediently, the production fluid expelling means comprises a pump in the riser arranged for pumping production fluid from the first passageway to the second passageway. The pump may be used to avoid hydrate formation instead of gas pressure control. According to a further development, a cyclone separator mounted on the pipe for positioning within the riser and having inlet means for imparting swirl to production fluid entering the separator from the riser to effect separation of the fluid into a liquid-rich underflow and a gas-rich overflow, the pump being arranged to receive the separator underflow and pump it up to the top of the riser through said pipe. This avoids formation of (air and production fluid) slugs.

Where the pump is held at a low point of the riser, it can be arranged that hydrostatic pressure at the pump inlet ensures that the bulk of, or all of, the gas

included in the hydrocarbon fluid rich underflow is held in solution by the time that the hydrocarbon fluid enters the pump.

In a modification, said hydraulic pump comprises a pump section, turbine section and an articulated or flexible coupling section to the packer or drive mandrel.

The articulated or flexible couplings between the turbine or pump section and the packer or drain mandrel enables the hydraulic pump to pass around tight bends within the riser.

Preferably, the coupling section comprises a universal drive coupling or an articulation incorporating a flexible coupling, in each case with a torque reaction device between the casings of the pump and turbine sections.

A universal drive coupling is a convenient form of element for maintaining drive as the pump and turbine sections articulate relative to one another.

Expediently, a heater is provided in the region of the hydraulic pump, the heater being arranged to be supplied by heating medium conveyed through said pipe. The heater avoids the formation of freeze-ups.

Due to the provision of the coupling section, the hydraulic pump can be passed through a riser having relatively sharp bends, such as the mentioned lazy-S, steepwave and steep-S configuration.

In some embodiments, the riser has a substantially vertical compliant section, leading from the sea bed to the surface, a substantially horizontal section on the sea bed, and a bend section connecting the substantially vertical and horizontal riser sections. This is a further typical pipeline configuration for which the provision of the hydraulic pump including articulated linking between the turbine and pump sections enables the pump to be advanced around the approximately 90° bend section where the radius of curvature is small, connecting the vertical riser section and horizontal flowline section of the riser.

In a further embodiment, a traction device on the pipe is operable for applying traction to the pipe to drive the operating device down inside the riser. The traction device enables the down-riser operating device to travel through a riser extending a long way, typically across the sea bed, from the surface access location to the top of the riser.

In a preferred embodiment, the traction device is selectively operable from the remote end of the pipe for applying traction to the pipe in either direction for lowering or raising the operating device. This enables the traction device to apply traction in either axial direction of the riser.

In another embodiment, where a down-riser pump is provided, a sealing device is mounted on the pump and arranged to provide a sliding seal with the inner surface of the riser, the pump being arranged to pump between a low pressure and a high pressure side of the sealing device so as to generate a traction force for driving the down-riser pump longitudinally within the riser, the pump and sealing device together constituting said traction device.

The down-riser pump together with its sealing device serves not only to provide down-riser pumping but also to generate the required traction force for driving the pump through the riser or flowline.

According to another embodiment, said operating device comprises a motor mounted on a lower end of the pipe and arranged to be powered by an electrical cable passing through said pipe, and a rotary cleaning device arranged to be driven by the motor. The rotary cleaning device is able to achieve cleaning (active or passive) of deposits on the inside surface of the riser wall. Furthermore, the motor is powered from the upper end of the riser via the pipe on which the motor is mounted, which is a convenient manner of powering the motor with ready access to the powering means at the riser upper end.

Preferably, a sealing device on the motor is arranged to form a sliding seal with the inner surface of the riser. Where a pump is provided, it may be arranged to provide differential pressure between a low pressure side and a high pressure side of the sealing device.

The differential pressure acts on the motor to create a force acting on it to drive it along the riser.

Alternatively, the rotary cleaning device is arranged to generate a differential pressure between one side and the other side thereof when it is rotating. The differential pressure generated by the rotary cleaning device serves to advance it within the riser or, where a pump is additionally provided, the force generated by the rotary cleaning device supplements the driving force acting on the pump itself.

A rotary cutter is able to provide active removal of hard scale build-up on the inside of the flow line/riser wall, a rotary brush provides less aggressive cleaning, whilst a combined rotary cutter/brush provides aggressive cutting for removing hard scale and more gentle cleaning for removing more readily removable deposits.

Corresponding to the system according to the first aspect of the invention are methods of installing a riser operating device.

In accordance then with a further aspect of the invention, there is provided a method of installing an operating device in a riser connecting a source of production fluid on the seabed to a top end support supporting the riser at or in the vicinity of the sea surface, comprising:-

- introducing the device into the riser at the upper end thereof; and
- driving the device downwardly into the riser to a desired operating position in the riser remote from its end at the top end support.

Preferably, the device is attached to the lower end of a rigid pipe and the pipe is driven downwardly into the riser to displace the device to its desired operating position.

According to a method of maintaining or replacing an operating device installed in accordance with the present method, the following steps are carried out:-

- driving the pipe upwardly to raise the device within the riser to the top end support;
- removing the device from the riser; and
- disconnecting the device from the pipe, for maintenance or replacement.

For adjusting the position of the pump, heater or gas injector (as the case may be) in the riser, it is preferred to carry out the following steps:- the pump, heater or gas injector is retrieved from the riser through its upper end and disconnected from the pipe, an end section of the pipe is removed or a new section attached to its end to define a new length of pipe, and the pump, heater or gas injector attached to the end of the new length of pipe and driven down the riser to its new operative position.

In a further development, the method comprises at least partially expelling the production fluid from the riser interior, so as to reduce the pressure acting there, in order to inhibit formation of solid hydrates in the production fluid flowing from the source under interrupted flow or shut down conditions.

Since the pressure acting in the riser and flowline interior can be reduced, particularly under no flow condition, the formation of solid hydrates in the riser can be inhibited at any given temperature. Of course, the pressure reduction must be sufficient to be below the hydrate formation pressure at the local temperature.

A pump is a simple and effective device for achieving the required expulsion of production fluid from the riser.

According to an alternative method, gas is introduced under pressure into the riser to at least partially expel the production fluid and the gas pressure acting in the riser is reduced to a value lower than its initial value while preventing the expelled production fluid from returning to the space occupied by the gas. This represents a simple and effective way of reducing the pressure in the riser. In fact, this arrangement also offers the advantage that the equipment needed for supplying the gas under pressure and then reducing its pressure does not need to be located at down-riser but, conveniently, can be located at the surface or top end of the riser.

A hydrate formation inhibitor may be introduced along with the gas. The inhibitor serves to augment the inhibition of solid hydrate formation.

It should be noted that where the term "rigid" is used in this specification to describe the nature of the pipe (or pipes) deployed within the riser, such pipe is able to follow the anticipated deviations from linear of the riser, by elastic deformation of the material, (typically steel or suitable composite plastics material) used to form the rigid pipe, such as occurs even in the case of the embodiments to be described below, in which the riser is also made of rigid material which is compliant to vertical and horizontal displacements of an attendant vessel supporting the upper end of the riser. It is alternatively possible for the riser to be made of flexible material rather than rigid material (while the pipe remains of rigid material), but then suitable positioning means has to be provided to position the top end support suitably relative to the lower end such that the rigid pipe is not deformed beyond its elastic limit. The rigid pipe needs to be sufficiently rigid to support the pump, heater or gas injector adequately when held in the desired position in the riser. Alternatively, the internal pipe may also be of flexible material.

The top end support for the riser may be simply an attendant, floating, support vessel. It will be appreciated that the system may include a submerged buoyancy unit as the top end support, whether a down-riser pump, heater or gas injector is used. In addition, a surface breaking extension (i.e. through the air/water interface) may be provided for access to the riser top end. This has the advantage that at the time of installation, the pump, heater or gas injector can readily be inserted into the upper end of the riser, since even when the top end support is a submerged buoyancy unit, the upper end of the riser is still readily accessible to crew members attendant on site.

Although the pump, heater or gas injector will normally be positioned in the riser in the vicinity of its bottom end, it is not necessary for it to be positioned there. For example it could be located at a mid-position or elsewhere within the riser or flowline, when desired.

For a better understanding of the invention and to show how the same may be carried into effect, reference will now be made, by way of example, to the accompanying drawings, in which:-

Figure 1 is a general schematic view of a first system for raising hydrocarbon fluid from a subsea source, forming a first embodiment of the invention;

Figure 2 is a more detailed side view of the riser of the system;

Figures 2a and 2b show respective modifications;

Figure 3 is a schematic view of a second embodiment;

Figure 4 is a side view showing in more detail the construction of the riser at a time when a hydraulic pump is being installed down-riser;

Figure 4a is a side view of the buoyancy unit and maintenance stack of the system shown in Figure 4;

Figure 4b shows a pigitable wye junction which can be used for pigging the system or for providing a radius suitable for pump insertion;

Figure 5 is a schematic view of a third embodiment, differing in certain respects from that according to Figures 1 and 2;

Figure 6 shows the arrangement in more detail;

Figure 7 is a schematic side elevation of a fourth embodiment resembling that shown in Figure 4 but differing in certain details;

Figures 8 to 10 show a schematic side elevation of a fifth embodiment of the invention showing evacuation of the riser by gas displacement or gas/methanol displacement;

Figure 11a shows a schematic side elevation of a sixth embodiment of the invention for use in slug suppression or separation;

Figures 11b and 11c are cross-sectional views along the planes 11b-11b and 11c-11c of Figure 11a;

Figure 12 shows a schematic side elevation of a further embodiment of the invention for use in pressure boosting or provision of artificial lift in an S-configuration riser;

Figure 12a is a partial schematic sectional view through the wall of a riser having a coiled spiral inner construction;

Figures 12b, 12c and 12d show schematic side elevational views of various riser configurations;

Figure 13 is a schematic side elevational view of a system according to the invention for providing pressure boosting or artificial lift from one or more subsea well in a rigid or compliant riser;

Figure 14a shows a schematic side elevational view of a system according to the invention employing a first method for transporting an operating device to or from a location remote from the riser top, using a coiled tubing delivery system;

Figure 14b is a schematic side elevational view of a part of the system of Figure 14a at an enlarged scale;

Figure 14c is a schematic side elevational view of a part of the system of Figure 14a showing a modification using a derrick system for tubing deployment;

Figure 15a shows a schematic side elevational view of a system according to the invention employing an alternative method for transporting an operating device to or from a location remote from the riser top using a coiled tubing delivery system;

Figure 15b is a schematic side elevational view of a part of the system of Figure 15a at an enlarged scale;

Figure 15c is a schematic side elevational view of a part of the system of Figure 15a showing a modification using a derrick system for tubing deployment;

Figure 16a shows a closed loop production mode cleaning apparatus for cleaning the inside of a riser;

Figure 16b shows an open loop production mode cleaning apparatus for cleaning the inside of a riser;

Figure 16c shows the use of shutdown mode annular fluid flow for driving a cutter for cleaning the inside of a riser; and

Figure 16d shows the use of shutdown mode coaxial fluid flow for driving a cutter for cleaning the inside of a riser.

The invention defined hereinafter in various aspects thereof, as well as the following embodiments, concerns a vertically accessed riser with retrievable internal services (referred to herein as VARRIS for short) and was conceived to provide energy addition (thermal or pressure) to fluids transported from the seabed to a production facility at, or a relatively short distance below, the sea surface, by inserting services into the riser/flowline at the topside interface rather than by external installation using a deepwater intervention vessel. VARRIS is based on the core concept of placing services into a riser and its flowline, the riser/flowline being either an existing installation or a new build. Further capabilities have been identified which use similar deployment philosophy but with different equipment to achieve new features and extend functional capability.

While VARRIS was developed for deepwater installations it is equally valid for shallow applications.

Further applications of the invention to be described below include installing a down-riser slug suppressor, separator, equipment tug or tractor, and scale/wax removal equipment.

Further applications of VARRIS cover the following areas:

1. Using VARRIS as a slug suppressor/separator (Fig. 11);
2. Using VARRIS to evacuate the riser/flowline (Figures 9 to 10);
3. Using VARRIS in existing risers (shallow or deepwater, rigid or flexible) for pressure boosting/provision of artificial lift (Figures 12a to 12d and 13);
4. Assistance in deployment/retrieval of the internal services towards/from the subsea production facility (manifolded production system or an individual well) along the seabed flowline section using a mechanical self-driven tractor (Figures 14a, 14b and 14c), or using self drive by generation of an axial differential

pressure and driving force across the end remote from the riser entry point at the top (Figures 15a, 15b and 15c); and

5. As for 3 but using a pig to assist in deployment/retrieval of the internal services (Figures 16a to 16d).

Referring to Figures 1 and 2, there is shown a first embodiment of the invention in the form of a system for raising, from the seabed or mudline 2, hydrocarbon production fluid in a flowline 1 from one or more subsea wells (not shown), the flowline running along the seabed or mudline 2. The flowline may be connected directly to the lower end of a riser 4, which extends up from the mudline to the sea surface 5, where the flowline is supported by a floating support vessel 6. If necessary or desired, as shown in Figure 1, the flowline may optionally be provided with a homogeniser 3 for homogenising the three-phase production fluid generally consisting essentially of crude oil, natural gas and water, and suitable valving, such as on-off valves 40, 41 and 42. When valves 41 and 42 are closed and valve 40 opened, the production fluid passes directly to the riser 4. However, on opening valves 41 and 42 and closing valve 40, the production fluid is routed via the homogeniser 3.

The riser 4 extends initially in a horizontal direction, forming an extension of flowline 1, and then curves upwardly, eventually becoming vertical. Although the curvature of the riser is depicted as relatively sharp, in fact this is due to the scale of the Figure and the actual curvature would be much more gentle since the system is installed at a large depth (which might typically be 100 to 500 metres or more) and the curvature of the riser is accommodated by elastic deformation of the material of which it is made. However, the riser 4 could be of flexible material with bend radius < 100m, for example.

The support vessel 6 is provided with a pipe delivery and retrieving apparatus, including a powered drum 7 on which a length of coaxial pipe 19 is wound. The pipe delivery and retrieving apparatus will generally include a pipe straightener for removing the residual "curl" of the pipe resulting from its being wound onto the powered drum 7, and also a tensioner for assisting in drawing the pipe from the

drum and forcing it through the straightener. One suitable form of pipe delivery and retrieving apparatus is disclosed in US-A-3,982,402.

An optional standard pipe lubricator or injector 8 is mounted on the vessel 6 and connected to the upper end of the riser 4, a length of pipe 19 paid out from the powered drum 7 passing downwardly through the lubricator or injector 8 and into the upper end of the riser 4, and extending to a position within the riser remote from its upper end, for a reason to be explained below. The lubricator or injector 8 provides a fluid-tight seal with the outer surface of the pipe 19. A crane 9 on the vessel serves for lifting and supporting pipe 19 dispensed from the powered drum 7. Since the riser has an undulating configuration between the seabed 2 and support vessel 6 as shown, it can be referred to as a compliant vertical access riser. The riser may also be of a simple catenary or S configuration. The purpose of the riser configuration is to accommodate vertical and horizontal vessel motion relative to the seabed 2 (such as due to wave action and sea currents), without placing any undue strain on the riser 4. As shown, there may be one or more additional riser 4 with corresponding equipment at the lower end thereof.

Figure 1 also shows a pump 14 and an optional heater 15, whose purposes are described below.

Figure 2 shows in some detail the structure at the lower end of the riser 4. The riser itself is of tubular construction. Mounted within the riser 4, for example centrally, by means of a packer 10, which is operable for forming a seal with the riser wall, is a hydraulic submersible pump or HSP 11, having an inlet 11<sub>1</sub> for receiving production fluid in the flowline to be pumped, and a pumped production fluid outlet 11<sub>2</sub> in the form of a plurality of exit openings arranged circumferentially around the HSP 11, discharging into the riser 4 at the opposite side of the packer 10 to the fluid entry point. The pump also has a hydraulic fluid inlet 11<sub>3</sub> and a hydraulic fluid outlet 11<sub>4</sub> or 11'4. The packer 10 is sealed to the riser wall, by means of an inflatable seal 10a of the packer 10, shown diagrammatically in Figure 2. In this case, hydraulic fluid is supplied to the seal 10a along an umbilical or inflation line 100, to inflate the seal and cause it to sealingly engage the inside

of the riser wall. Alternatively, suitable ducting with control valves or a retrievable internal diverter in the supply pipe 12 may be provided between the HSP 11 and the inflatable seal 10a, so that hydraulic fluid from the pump may be used to inflate the seal. In both cases, the seal 10a may be deflated, to break the seal with the riser wall, by releasing the hydraulic pressure acting on the inflatable seal 10a.

In another form, the seal may be mechanically operated or electro-mechanically operated. Various forms of seal which would be suitable for the intended purpose are known to those skilled in the art. By way of example, one such seal would be in the form of a sealing member operative (for example by a biasing or latching action) to sealingly engage in a groove formed in the riser inner wall surface. In this example, a groove would need to be provided at each location in which the seal is to be made operative.

The length of rigid pipe 19 extending downwardly through the lubricator 8 (Figure 1) and along the length of the riser is preferably a nested arrangement of hydraulic supply and return pipes 12, 13. The pipe 19 may preferably have a construction such as shown in US-A-5,638,904 in which the supply and return pipes 12, 13 are formed into a helical configuration which may lock it firmly within the riser 4. The supply pipe 12 is normally the central pipe and is connected to supply hydraulic fluid to pump inlet 11<sub>3</sub>, thereby driving the pump 11 to increase the pressure of the production fluid entering the pump through inlet 11<sub>1</sub> and drive it from pumped fluid outlet 11<sub>2</sub> up through the riser 4 to the support vessel 6. The hydraulic fluid outlet 11<sub>4</sub> can be connected directly to the return hydraulic pipe 13, but may alternatively be connected indirectly through a further short length of coaxial pipe 29 comprising central supply pipe 12a and surrounding return pipe 13a interconnecting at their remote ends. This coaxial stub pipe 29 constitutes a heater or "stinger" which permits the production fluid to be heated in a region of the riser 4 beyond the pump 11 by supplying hydraulic fluid heated on the vessel 6 by heater 15. The return pipe 13a either passes via the pump internally, or passes externally of the pump but within the riser, and is connected to return pipe 13. In a modified arrangement, part of the pump outlet hydraulic pressure is connected directly to the return hydraulic pipe 13, the remainder being bled off to feed central supply

pipe 12a. In this way, a total or partial hydraulic circulation circuit is provided from the support vessel 6 through supply pipe 12, HSP 11, supply pipe 12a, and back through return pipes 13, 13a to the vessel 6. The hydraulic pressure circuit can be a closed circuit or it may be an open circuit with the recirculated fluid stored in a tank or separated and discharged overboard, which would be appropriate if the hydraulic medium is water, for example. In another configuration, the hydraulic supply from pipe 12 is partially discharged into the outlet 11<sub>2</sub> of the pump 11.

Hydraulic pressure fluid is circulated around this circuit by pump 14 in order to drive HSP 11, which in turn pumps production fluid up the riser 4 to the support vessel 6, where the production fluid can be treated (such as in a separator to separate the components, principally crude oil, water and gas), stored, pumped to an attendant tanker or pumped ashore via a suitable pipeline. The heater 15 is preferably provided, so that the circulating hydraulic fluid can be heated, to raise the temperature of the hydrocarbon fluid in the riser through heat conduction through the walls of the supply and return pipes 12, 13 and convection into the hydrocarbon fluid. The optional "stinger" or heater 29 serves to heat up the production fluid entering the riser 4 from the flowline 1 or to unfreeze solids formed in the riser 4 following extended shut-downs. The heating provided by the circulating hydraulic fluid avoids the risk of freeze-ups when operating in particularly cold environments or when the system is to be taken out of operation temporarily.

The coaxial pipes 12, 13 serve not only to circulate hydraulic pressure fluid through HSP 11 to drive it, but also to physically carry the HSP at their end remote from the vessel 6. Furthermore, the packer 10 on which the HSP is mounted can be operated to break its seal with the riser wall, under which condition the packer 10 can slide within the riser over its whole length. Therefore, by winding in the coaxial arrangement 19 onto the powered drum 7, the HSP can be raised to the upper end of the riser for maintenance or repair. This operation is described in detail below.

The installation of the flowline 1, deployment of the riser 4 from the support vessel and connection of the riser 4 to the flowline 1 can be carried out in accordance with well-known techniques, which will therefore not be described herein. At this stage, the length of coaxial pipe 19 is stored on powered drum 7 and the lubricator/injector 8 is disconnected from the upper end of the riser 4. To install the HSP 11 in the riser 4 adjacent its lower end, an initial length of the coaxial pipe 19 is passed through the lubricator/injector 8, or riser top end hang-off, by the pipe laying and retrieving apparatus and the HSP 11 is attached to the free end of the coaxial pipe, after which the HSP 11 is inserted into the open upper end of the riser 4 with packer 10 set in its non-sealing condition and the lubricator/injector 8 connected to the upper end of the riser 4. Then, the pipe laying and retrieving apparatus discharges the remainder of the coaxial pipe 19 stored on powered drum 7, to displace the HSP 11 down the riser 4 until it reaches its desired final position remote from the upper end of the riser 4. The seal 10a of the packer 10 is then engaged with the riser wall and the upper end of the coaxial pipe is disconnected from the pipe laying and retrieving apparatus, and then connected to the pump 14 and heater 15, ready for operation. It will be appreciated that the length of coaxial pipe 19 needed has to be determined beforehand and the appropriate length stored on the powered drum 7 beforehand, so that when the HSP 11 reaches its required final position in the riser, the appropriate length of pipe 19 has been dispensed. Additional pipe sections can be stored on the drum as required to be used as extensions. The coiled pipe 19 may alternatively be driven into the riser by the injector 8 such that it adopts a helical form within the riser 4, thereby locking it in position within the riser 4.

If the HSP 11 needs servicing or malfunctions, it can be retrieved to the vessel 6 by essentially a reversal of the above-described operations. Accordingly, the upper end of the coaxial pipe 19 is disconnected from the hydraulic pressure circuit and re-connected to the pipe delivering and retrieving apparatus, for example with assistance from the crane 9. The coaxial pipe in turn re-wound onto the powered drum 7 to raise the HSP to the upper end of the riser 4, the lubricator/injector 8 disconnected from the riser, the HSP 11 removed from the riser and disconnected from the coaxial pipe 19, and the coaxial pipe 19 withdrawn

from the lubricator 8 and wound fully onto the drum 7. The HSP 11 can then be repaired or replaced, before being deployed in the riser 4 in the manner described for the initial installation.

Figure 2a shows a modification in which a single, delivery pipe 12 is provided inside the riser 4, but no return pipe 13. Instead, the hydraulic fluid discharged from the outlet 11<sub>2</sub> of HSP 11 is released directly into the flow of production fluid pumped up the riser 4. In this embodiment, the hydraulic fluid must be one which it is acceptable to mix with the production fluid. One such example is water, since the production fluid usually has a water content, for which a separator will normally need to be provided on the support vessel 6.

In another modification shown in Figure 2b, the down-riser pump 11 is an electric pump carried on the end of a single pipe 12, through which a power supply cable 16 passes, connected between a power source on the vessel 6 and the electric pump 11. Although the electric pump 11 is shown to be similar in size to the hydraulic pump 11 of Figure 2a, it will be appreciated that in a practical embodiment it will be much longer. If it is desired to provide heating for the production fluid, an electric heater 18 may be provided, such as at a position between the lower inlet end of the riser 4 and the electric pump 11. A further power cable 16a, connected to main power supply cable 16 and passing through a short section of rigid pipe 12a on an end of which heater 18 is mounted, supplies electric power to the heater 18.

Referring to Figure 3, there is shown a schematic diagram of another embodiment. Where the same reference numerals are used as in the previous Figures, they denote the same or equivalent elements and the description of them is not repeated here. This embodiment differs from the preceding ones principally in that the top of the riser 4 is connected to a buoyancy unit 20 tethered to the sea floor and positioned just below sea level 5. Since there is no need to accommodate any vertical motion of the buoyancy unit, the riser 4 takes the form of a rigid tubular element and it extends vertically upwardly from a riser base 21 secured to the seabed 2. The riser base 21 is connected to receive production fluids from a

well via flowline 1. The buoyancy unit 20 is provided with a flexible take-off hose 22 suspended in the sea between the buoyancy unit and an attendant service vessel 6, for conveying hydrocarbon fluid from the top of the riser 4 to the vessel 6 for processing or onward transportation.

As shown in Figure 4, when provided, the homogeniser 3 is located in the riser base 21. The production fluids in flowline 1 leave the homogeniser 3 (when provided) and enter the riser 4 at its bottom end. Situated a short distance above the riser bottom end inside the riser is the HSP 11 carried on the bottom end of coaxial pipes 12, 13. The internal arrangement of the HSP, its packer 10 and heating "stinger" 29 is identical to that shown in Figure 2.

The manner in which the riser base 21, riser buoyancy unit 20 and flexible hose 22 are installed is conventional in itself and therefore will not be described herein. However, in order to install the HSP on the lower end of coaxial pipe 19 in the riser, the buoyancy unit 20 is provided with a detachable maintenance stack 24 connected to a wye ("Y") junction 25 which is mounted on the buoyancy unit 20. This wye junction 25 is either of piggable or non-piggable configuration. The wye junction 25 serves for routing the production fluid from the riser 4 to the flexible hose 22. The maintenance stack 24 includes a lubricator 8 extending over most of the height of the stack, and vertically spaced blowout preventer valves 26 and 27 with isolation facilities. To install the HSP 11, the support vessel 6 or another service vessel is positioned over the buoyancy unit 20. At this time, the maintenance stack 24 is on-board the vessel 6. The free end of the coaxial pipe 19 wound on the powered drum 7 on the vessel 6 is passed into the stack 24 from above, through the lubricator 8, blowout preventer valves 26, 27 and emerges through the bottom end of the stack 24. The HSP 11, together with its packer 10 (with its seal inoperative), is then attached to the projecting end of the pipe 19 and withdrawn fully upwardly inside the stack, after which the maintenance stack 24 is lowered from the vessel 6 into the sea, and connected to the wye junction 25 by remote control. The powered drum 7 is then operated to drive the pipes downwardly into the riser 4 until the HSP 11 reaches its required lower position in the riser. The packer seal 10a is made operative to seal with the riser wall.

Shortly before the HSP 11 reaches its final position, the upper end of coaxial pipe 19 comes off the powered drum 7, the weight of the pipe and pump 11 in the riser 4 being supported by the tensioner of the pipe delivery and retrieving apparatus, which grips the upper end section of outer pipe 13. Then a conventional so-called "hang-off" device (not shown) is attached to the pipe end, followed by another short length of auxiliary pipe 49 which can be wound on the powered drum 7 or may already be wound on the drum, or carried by the crane 9 on the support vessel 6. The drum or crane, as the case may be, then lowers the auxiliary pipe 49 until the hang-off device has passed through the lubricator 8 and the pump 11 is just very slightly above its final position. The hang-off device is now actuated and the auxiliary pipe 49 lowered the final short distance to engage the hang-off device with the buoyancy unit 20 and support the weight of the coaxial pipes 12, 13 and pump 11 in the riser 4. Figure 4 shows the system at this stage. Following this, the maintenance stack 24 is disconnected from the wye junction 25 and raised, together with the auxiliary pipe 49, back to the support vessel 6. Finally, as shown in Figure 4a, a pressure cap 50 is fitted by means of a running tool to complete the necessary hydraulic connections between hydraulic pipes 45, 47 and the coaxial pipes 12, 13 and provide operating and environmental seals.

As shown in Figure 4a, a hose 43 for hydraulic fluid 43 supplied from the support vessel 6 conveys hydraulic fluid to the buoyancy unit 20, where it passes through connecting line 44, including an isolator 45, to supply line 12, down to HSP 11 and back up return line 13 to the buoyancy unit 20 through connecting line 46, including isolator 47, from where the hydraulic fluid is returned to the support vessel 6 by hose 48. In this way, the HSP 11 is hydraulically powered, to pump hydrocarbon fluid up the riser 4.

Retrieval of the HSP 11 back to the vessel 6 for maintenance or replacement is essentially a reversal of the above steps, just as in the preceding embodiments. Therefore, no description is given of this retrieval procedure.

As shown in Figure 4b, if the riser 4 is to be piggable, the wye junction 25 can be replaced by a wye junction 28 turned the opposite way up. Conveniently, a gooseneck pipe 23 is connected to the wye junction 28, for supplying pigs to be introduced into the riser 4. The HSP 11 has to be raised to a position above the wye junction 28, before the pigging operation can begin. Where the size of the HSP permits, the gooseneck may allow deployment of the HSP from the vessel 6 by insertion through the take-off hose 22 down to its operating position.

The system of Figures 4, 4a and 4b for raising hydrocarbon fluid can be modified in accordance with the modifications according to Figures 2a and 2b, in corresponding fashion. In the former case, the riser will include a single rigid pipe, that is the hydraulic supply pipe 12 supplied from hose 43. In the latter case, the power supply line for the electric pump 11 runs inside hose 43 and down inside pipe 12. Of course, the HSP can be replaced by an electric pump in the other embodiments as well.

In the preceding embodiments, the down-riser pump, whether hydraulic or electric, is mounted inside the riser. However, in the modification of Figures 5 and 6 to the system according to Figures 1 and 2, the coaxial pipe arrangement 19 is used solely for circulating heating fluid to a heating "stinger" or heater 30, positioned adjacent the lower end of riser 4, and one pump of a pair of electric pumps 31, 32 mounted externally of the riser 4 in series with it is used for driving the production fluid up the riser. Two pumps are provided for redundancy and in view of the difficulty of repairing a pump in situ or recovering it to the surface of the sea. If one fails, the other can be brought into service using the switchgear 33, to take over from the first pump. The power supply line 34 for the electrically driven pumps is carried on the outside of the riser 4 and connected to the switchgear 33 via power connector 35. This system does not offer the above described advantages that would arise if the pump were mounted inside the riser and retrievable to the support vessel or buoyancy unit, but it does avoid the risk of freeze-ups due to the delivery heat to the lower end region of the riser. It also enables the heater to be retrieved to the top end support, i.e. the support vessel 6, for repair or replacement. As an alternative to the electrically driven pumps, there

may be used hydraulic pumps. Furthermore, if the production fluid pressure in flowline 1 is large enough, the external pumps are not required.

In accordance with another embodiment shown in Figure 7, the single pipe 12 such as included in Figure 2b or in the Figure 4 embodiment as modified in Figure 2b is used solely for supplying gas under pressure to a gas injector in the riser, for creating gas lift for raising the hydrocarbon fluid in the riser. Figure 7 shows a system with buoyancy unit 20 similar to that shown in Figure 4. In Figure 7, the injector or poker is shown diagrammatically at 36. The pressure gas is supplied to the injector 36 via a hose from the support vessel to the buoyancy unit 20 and down to the injector. This system exhibits the advantage that, where it is appropriate to use gas lift, the need to supply the lift gas via an external pipe is avoided. This also avoids having to form an aperture in the wall of the riser 4, so that the pressure gas supply line can pass through the riser wall. Again, the gas injector 36 can be raised for maintenance or replacement and a heater and/or HSP in the riser is optional, according to needs.

In the embodiments of Figures 5, 6 and 7, the heater 30 and gas poker 36 in each case are preferably guided in the riser 4 by an element similar to the packer 10, with the difference that, when actuated, it engages with the riser wall but it does not need to seal with it.

In all of the above-described embodiments and modifications, the pipe arrangement 19, which may comprise two or more nested pipes or a single pipe, is preferably made of steel or suitable composite material, so as to have a sufficient degree of rigidity such that as the pipe delivery and retrieval apparatus drives the pipe arrangement 19 down the riser 4, the riser will not flex significantly or buckle, such as to cause jamming or damage to any part of the system, particularly the pipe arrangement 19 itself. It is also pointed out that since the pipe arrangement 19 is relatively heavy due to its large size (for example a coaxial pipe might typically have an outside diameter of 7.5 cm to 12.5 cm) and large wall thickness (for example for steel coaxial pipes, the wall thickness of each pipe might suitably be some 9mm thick), as more of the pipe length is deployed down the riser the

deployed weight increasingly assists in pulling the pipe length off the powered drum 7. The tensioner of the pipe laying and retrieving apparatus can then serve to support part of the weight of the pipe arrangement.

It is also mentioned that a standard lubricator also generally has drive tracks which assist the deployment of the pipe length.

It is also considered that a steel pipe, for example, will also have sufficient elasticity to bend slightly to follow any non-linearity in the riser 4 itself resulting from its compliance to accommodate motion of the top end support, such as support vessel 6 or buoyancy unit 20, relative to the flowline 1 on the sea bed. However, whilst it is preferred to use a pipe delivery and retrieval apparatus such as described, nevertheless another workable option would be to use coaxial pipes (or a single pipe), which are flexible. In that event, the means for conveying the pump down-riser would suitably take the form of a pig or towing gland that slideably closes the annulus between pump and riser/flowline attached to the pump itself or to a lower part of the pipe, which is then driven down the riser by introducing hydraulic pressure into the upper end of the riser above the pig. One possible way of implementing this teaching is to design the packer fitted on the HSP to function as a pig.

Reference is now made to further embodiments according to Figures 8 to 11, 11a to 11c, 12 and 12a to 12d, 13 to 15 and 16a to 16d. These embodiments bear similarities in a number of respects to the preceding embodiments, and where possible corresponding reference numerals are used. Accordingly, the following description is confined mainly to differences in construction or operation.

Reference is now made to Figures 8 to 10 for a description of using VARRIS as a means of evacuating the riser/flowline by gas displacement or combined gas/methanol displacement, or by action of the pump.

In order to avoid the problem of hydrate formation, a solution can be afforded by a method of using coiled tubing 19 (either a single or coaxial tube) inserted inside

the riser 4, or the riser and flowline, via the tubing head at the top of the riser to remove the fluids (and hence the residual head from the riser 4 and its flowline 1) to a point where the remaining fluid static head in the riser/flowline is lower than the hydrate formation pressure. By using this technique another method of hydrate control is available that can be used either on its own or in combination with other methods and offers greater security against blockage. Furthermore as the location of the drain/venting system is within the riser 4 there is no requirement for external intervention as in conventional techniques.

In the embodiments to be described with reference to Figures 8 to 10, at least one conduit internal to the riser and flowline enables evacuation of fluids thereby reducing the static head in the riser/flowline system on flow interruptions/shutdowns below the hydrate formation pressure. The or each conduit may comprise coiled tubing 19 or multiple pipe lengths inserted at the riser top end. The lowest point of fluid evacuation is at any point in the riser/flowline between the riser top and subsea wellhead. The conduit 19 may be used as part of a separate system, e.g. as part of a pump power fluid supply or liquid heating line. In Figures 8 to 10, the coiled tubing 19 comprises an outer tube 118 and an inner coaxial tube 115.

Figure 8 shows a closed-loop variant implementing concepts as outlined above. A flowline 1 is connected via a check valve 125, providing limited leakage, to the inlet of a hydraulic pump 11, which is sealed to the inner surface of the flowline 1 by a packer 10 having a releasable seal. The check valve 125 may alternatively form part of the pump inlet tract or packer 10. Following isolation of the flowline 1, a means of removing the fluid contents of a riser 4 and its flowline section downstream of the VARRIS barrier provided by the pump 11, or packer 10, is provided by the injection of gas via an inlet valve 129 into the annulus 105 between the inner wall of riser 4 and the coiled tubing 19. This causes the fluids to be forced through a riser evacuation port 126 and back to the surface via the annulus 114 between the outer tubing 118 and the inner tubing 115 exiting via a valve 130. On completion of fluid removal, the annulus 105 is depressurised resulting in equalisation of pressure across check valve 125, and ultimately

providing a pressure in the flowline 1 immediately upstream of the packer 10 equal to the gas pressure in the riser annulus 105.

The operating method will now be described in detail. In the no flow condition, the system settles down such that there is negligible differential pressure across check valve 125.

In normal production, the pump 11 is operated by hydraulic fluid supplied via valve 131 and exhausted via valve 130. To remove fluids from the riser 4 following a cessation of production, the main production valve 128 and drive fluid inlet valve 131 are shut. Gas is added to the annulus 105 between the outer tubing 118 and the riser 4 via gas access valve 129 until the differential pressure, or flow back towards the flowline 1, causes check valve 125 to close. Alternatively, fluid may fall back in the annulus 105 which will close check valve 125. Further addition of gas via gas access valve 129 increases the pressure in annulus 105 until the check valve in the riser evacuation port 126 opens. Still further addition of gas via valve 129 results in the fluids flowing via the riser evacuation port 126 into the annulus 114 between the inner and outer tubings 115 and 118 and back up to the surface to exit via the drive fluid exhaust valve 130.

Evacuation is continued until the fluid level in the riser annulus 105 has reached a predefined level.

The gas in annulus 105 is now vented or recompressed and stored under reduced pressure at the top of the riser, thereby reducing the differential pressure across the check valve 125 until it opens. A higher upstream pressure in the flowline 1 may deliver a small volume of fluid through the pump 11 into the annulus 105. This fluid can be removed by re-application of the above cycle one or more times, until the pressure in the annulus 105 ideally approaches atmospheric pressure. On completion, the check valve 125 remains open and the pressure in the riser annulus 105 is bled to a low value (or vacuum). The resulting residual pressure in the flowline 1 upstream of the check valve 125 is then purely a function of the head of fluid in the flowline 1. Due to the substantially complete removal of

hydrocarbon production fluid in annulus 105 and the relatively low pressure achieved in this annulus, hydrate formation in the riser during production interruption can be avoided.

The production fluid now vented from the riser annulus 105 into the annulus 114 between the inner and outer tubing 115 and 118, is circulated to topside for processing or storage. The fluid may be completely evacuated from annular space 114 by circulating pump drive fluid via drive fluid inlet valve 131.

An open-loop variant is shown in Figure 9. The principal difference from the closed loop variant of Figure 8 is that the pump drive fluid is exhausted into the riser annulus 105 along with the boosted product from the flowline 1 and there is a single drive fluid conduit 115 between the surface and the pump 11. Operation will now be described in detail.

In the no flow condition the system settles down such that there is negligible differential pressure across check valve 125.

To remove fluids from the riser 4 following a cessation of production, the main production valve 128 is shut. Methanol (or other hydrate formation inhibitor) and gas are added to the annulus 105 between the tubing 19 and the riser 4 via gas access valve 129 until the differential pressure, or flow back towards the flowline 1, causes check valve 125 to close. Further addition of gas via gas access valve 129 increases annulus 105 pressure until the check valves in the riser evacuation port 126 opens. Further addition of gas via valve 129 then results in the fluids flowing via the riser evacuation port 126 into the tubing 115 and back up to the surface to exit via the drive fluid valve 131. Check valve 176 closes to prevent flow through the turbine section of the pump.

Evacuation is continued by further addition of gas/methanol until a predefined volume of total liquid is retrieved to the surface. The gas in the annulus 105 is now bled to store at reduced pressure; reducing the differential pressure across the check valve 125 until it opens. A higher upstream pressure in the flowline 1

may deliver a small volume of fluid through the pump into the annulus 105; this fluid can be removed by re-application of the above cycle. On completion the check valve 125 remains open and the annulus pressure in the riser 4 is bled to a low value (or vacuum). The resulting residual pressure in the flowline 1 upstream of the check valve 125 is then purely a function of the head of fluid in the flowline 1. The small residual volume of product, methanol and gas remains within the tubing 115 and is circulated back to the riser annulus 105 on restart.

Figure 10 shows the use of VARRIS as a means of evacuating the riser flowline by use of pump 11.

Following isolation of the flowline the internal riser services incorporate a means of removing the fluid contents of the riser 4, and its flowline section 1 downstream of the VARRIS barrier provided by the pump 11, or packer 10, by using internal valving 132, 133 within the pump 11 to drain the riser 4 and utilising the power fluid exhaust route 114.

The operation will now be described. In the no-flow condition, the system settles such that there is negligible differential pressure across check valve 125.

To remove fluids from the riser 4 following a cessation of production, the main production valve 128 is shut and the pump's riser evacuation valve 132 is opened, together with an annulus by-pass valve 133. This operation may also include operation of internal valves within the pump casing to bias check valve 125 shut. The pump 11 is now driven in the conventional manner. However, fluid in the riser 4 is now delivered to the annulus 114 between the inner and outer tubing, and is then exhausted via the fluid outlet valve 130. Normally, drive fluid will be supplied via valve 131 and exhausted through valve 130 to drive the pump 11 in the forward direction. However, the same result could be achieved by reversing the direction of drive fluid flow (i.e. in via valve 130 and out via valve 131), thus driving the pump in reverse, and by suitable valving within the pump to cause evacuation of riser 4.

Evacuation continues until a predetermined volume of fluid has been retrieved, at which point either circulation continues to flush the VARRIS inner and outer tubing, or an inhibitor (e.g. methanol) is fed into the riser 4 via gas access valve 129 and circulated into the drive fluid return annulus 114.

Figure 11a relates to VARRIS as a slug suppresser/sePARATOR.

Instead of using external slug suppression/separation equipment, the embodiment of Figure 11a is based on the principle of installing this equipment within the riser 4 or its flowline, thus avoiding the need for additional surface vessels, as installation and maintenance is conducted from the riser tubing head interface at the destination facility.

For the purpose of this description, the riser 4 may be considered to include a flowline 1 on the sea bed, a transition zone 107 and a separation zone 108.

Such system operates by using the energy lost in the riser's separation zone 108, to assist in separating the liquid and gas phases using a series of three, nested, e.g. collinear, tubular pipes 103, 118 and 115. The separation is cyclonic and preferably incorporates a cyclonic, or helical, insert, to assist in partitioning the gas and liquid phases. The gas phase is directed upwards from this separation zone 108 while the liquid phase is driven downwards from the separation zone 108 towards the pump 11, by a combination of gravity and pump suction. The pump 11 is preferably set sufficiently low that the bulk of any remaining gas bubbles are re-absorbed by the liquid prior to entry into the pump 11 from where the liquid is boosted and transported to the surface via a tubing annulus.

Referring to Figure 11a, the VARRIS services are intended to divide the riser 4 or flowline into discreet zones in which the products phases can be separated and recovered by different flowpaths. Transportation of each phase will utilise internal energy, and added energy combinations. Any liquid phase (which may incorporate one or more gas phases or gases in solution) is anticipated to be lifted by one or more pump located within the riser or flowline.

Product in the flowline 1 enters the VARRIS zone via the packer 10 that is attached to the outer VARRIS tubing 103 at its lowest end. (Note: the arrangement is shown in the horizontal section on the seabed. The description is exactly the same should the system be installed in the vertical riser section 4). The product flows via the annulus 105, between the riser 4 or flowline 1 and tubing 103. As the fluid rises towards the riser packer 106, there is an increase in gas breakout and slug formation (successive gas and liquid slugs) over the transition zone 107. The mixed phase flow enters the base of the separation zone 108, where a perforated tubing section 109, directs the fluid into the separator. The height 'H' above seabed of the riser packer 106, perforated tubing 109, and separation zone 108, is set to achieve the desired flow characteristics and is expected to be varied as the produced fluid characteristics (e.g. water cut, flowrate, viscosity, temperature and pressure) change with time. Normally, this height will be reduced as the wellhead pressure reduces. This can be done by withdrawing the entire VARRIS apparatus from the riser 4, repositioning the packer 106 (such as by releasing its securing bolts (or other fastening means), resecuring them in the desired new position on the outer VARRIS tubing 103, and then reinstalling the device inside the riser 4 or flowline 1. If the position of the pump 11 is to be altered in the horizontal section, this can be done while the device is withdrawn from the riser, by re-setting the relative positions of the middle tubing 118 and the middle tubing hanger 120.

Reference is now made to Figures 11b and 11c, which are horizontal sectional views taken along the lines 11b-11b and 11c-11c respectively in Figure 11a. As shown in Figure 11c, positioned inside the perforated tubing 109 is a cyclone insert 123, defining substantially tangential inlet passages 1231 so as to create swirling of the fluid entering the separator zone. As is well known, this swirling or cyclonic separation causes denser, liquid rich, fluid 1232 to sink and leave the separation zone 108 as underflow and less dense, gas rich, fluid to rise in the separation zone 108 and leave as overflow. Other constructions, well known per se, for creating cyclonic separation can be used instead of the specifically described arrangement.

Therefore, within the separation zone 108 the production fluid enters the separator, which operates such that liquids will be directed to travel circumferentially downwards whilst a gas rich mixture migrates upwards. The upper section of the perforated tubing 109 allows the gas to flow at 110 into the upper annulus 111 between the riser 4 and the outer VARRIS tubing 103. Liquid carried over into the upper section is free to return to the lower riser section via perforations located at the lower end of tubing 109 above the packer 106. Gas continues to rise to the tubing head 124 where it exits at gas outlet 112.

Liquid in the separation zone 108 descends towards the pump 11 via the annulus 114 between the VARRIS outer tubing 103 and VARRIS middle tubing 118, where it enters the pump at 116. The boosted liquid is exhausted from the pump at 117 into the annulus 119 between the VARRIS middle tubing 118 and the pump power supply tubing 115. The boosted liquid is then driven up the riser to the tubing head where it exits at 121.

Locating the pump 11 in the horizontal flowline section 1, which is the low point of the riser, encourages the hydrostatic pressure to force any gas in the liquid underflow back into solution.

The pump drive may be either hydraulic (HSP) or electrical (ESP). In the former case the power fluid enters via the tubing 115 and is fed to the pump turbine where it will be either exhausted into the annulus 119 together with the boosted product (this is referred to as open loop), or returned via a coaxial return line 115A external to the pump power supply tubing 115 (this is referred to as closed loop). In the ESP case the power cable would be run inside the pump power supply tubing 115.

As shown, the apparatus incorporates measures, similar to that disclosed with reference to Figures 8, 9 and 10, to inhibit solid hydrate under flow interruption or shutdown conditions by removal of the liquid head in the riser annulus 105 into annulus 119 using gas displacement. In particular, pump 11 operates to expel

production fluid in the riser, via one-way pressure valve 126, to the low pressure region at the upper end of the riser, thereby reducing the pressure acting in the region of the riser 4 formerly occupied by the production fluid.

Therefore, the separation device according to Figures 11a to 11c comprises integral artificial lift that is installable in a riser or its associated flowline and incorporates a plurality of nested or un-nested tubings run from the top end of the riser using combinations of coiled tubing or jointed straight pipe sections. The device may be installed and operated in an existing riser or a newly installed riser. Furthermore, it may be operated in a vertical riser, buoyant tower riser, catenary riser, compliant vertical access riser, S-configured riser or wave configured riser. The riser may be constructed from continuous steel tubing, composite pipe (metallic and non metallic materials and hose) or combinations of these. The riser may also be dynamic and freely suspended from a buoyant body, or rigidly attached to a structure.

The device may be able either in part or in its entirety to enable maintenance or reconfiguration of the separation elements.

The device offers the facility to evacuate production fluids from the flowline/riser and remove the residual pressure head or the contents left within the flowline.

In conventional systems, successive slugs of gas and liquid in transition zone 107 are brought to the upper end of the riser and separated by a slug catcher, followed by multi-stage separation. The integral slug suppressor separator included in the riser system according to Figures 11a to 11c in effect performs the function of the slug catcher and the first stage separator of the conventional system and represents a simpler, cheaper, yet effective slug separator/suppressor.

It will be appreciated that, when functioning as a slug separator/suppressor, the function of the pump, primarily, is to pump the liquid underflow from the cyclone separator up to the surface at the top of the riser. When positioned low down in the riser, it can also function to maintain gas dissolved in the liquid underflow in

solution right up to the surface. It also has the further function of assisting in inhibiting solid hydrate formation, as described above.

Figure 12 shows the use of VARRIS in an existing riser (shallow or deep water, rigid or flexible) for pressure boosting/provision of artificial lift. A problem for installing VARRIS in an existing riser arises where the riser includes relatively sharply bending sections. A hydraulic pump for a given pumping capacity will generally be preferred to a similarly rated electric pump since it is typically much shorter, e.g. 4-5 m long as compared with 30-50 m long for an electric pump, and can therefore pass through a sharper bend in the riser. For this reasons, an electric pump would typically be used only in vertical risers, and hydraulic pumps would be employed in risers having bends.

Some risers are of coiled spiral inner construction, with an outer reinforced casing, or other similar form (see Figure 12a), enabling the riser to undergo sharper bends than would otherwise be possible. Even a hydraulic pump has difficulty passing around sharp bends because of the risk of getting stuck. The embodiment according to Figure 12 is designed to overcome this problem.

Figure 12 shows a system for boosting or providing artificial lift from a subsea well in a flexible riser hung from a floating surface body or via tubing head 122. Casing flexibility and torque reaction are achieved by mechanical and/or elastomer means, as will be described below.

The pump packer 102 and check valve 125 are located within the homogeneous bore section of the end termination 142 of the composite riser 4 and the riser base/manifold spool 143. Fluid from the flowline 1 enters the pump 11, powered via hydraulic power supply 115, and, in corresponding manner to that occurring in the embodiments according to Figures 8 to 10 described above, is exhausted into the riser annulus 105, where it flows to the surface. Riser evacuation is achieved by the same process as described above with reference to Figures 8 to 10.

The pump 11 comprises a hydraulic pumping section 113a, a turbine section 113b for powering the pump section and where required, a flexible coupling section 113c.

It will be appreciated that the articulation between the pumping section 113a and the packer 102 enables the pump 11 to encounter and negotiate relatively tight bends in the riser, and significantly tighter than if the articulation was not provided, without becoming jammed. Furthermore, the fact that a hydraulic pump is used, which is typically much shorter than an equivalently rated electric pump, contributes to the ability of the equipment to negotiate relatively sharp bends.

For installation the pump is passed on its hydraulic power supply pipe 115 down into the riser 4, and articulates around the composite riser bends by means of flexible coupling 113c. The power supply pipe 115 is optionally supported as required by intermittent spacers 144.

Evacuation of the riser annulus uses the same techniques as described with reference to Figures 8 to 10 above.

The above system is also applicable to various riser configurations, e.g. the so-called lazy-S (Figure 12b), steep wave, (Figure 12c) and steep S (Figure 12d) configurations.

It will be appreciated therefore that this embodiment finds particular application to shallow water applications.

Referring now to Figure 13, there is shown a system for boosting or providing artificial lift from at least one subsea well or at least one subsea field in a rigid or compliant riser suspended from a fixed platform shown schematically at 151.

In this embodiment, the riser 4 is a rigid tube suspended from a static hang off point on the fixed platform 151, and guided/supported by the platform at intermediate points, 152, along the length of the riser. Although the pump 11 is

shown in the vertical section it can be installed past the base bend 153 of the vertical riser section leading to the horizontal section lying on the sea bed, by virtue of the flexible coupling 113c that permits articulation.

Where the pressure boost/artificial lift afforded by the pump 11 is not required, a heating line and heater can be used as in embodiments such as according to Figure 2b. Of course, the present embodiment may include such heating line and heater in addition to the pump assembly, where artificial lift and heating are both required.

Reference will now be made to Figures 14 and 15, which show embodiments capable of transporting VARRIS equipment to/from a location remote from the top insertion point on a riser.

In general, to position permanent components axially along a riser/flowline, motive force can be provided by:-

1. gravity acting on the vertical elements of a deployment string;
2. a pushing force applied at the riser entry point of the deployment string (according to VARRIS);
3. flow within the riser/flowline driving a towing pig;
4. an electrically driven tractor unit; or
5. combinations of these methods.

1/. & 2/. are limited by the ability of the string to accommodate buckling forces, 3/. requires a circulation path (i.e. a flowline loop), and the towing pig must not offer undue resistance during normal production operations. 4/. requires an umbilical to be run with the tractor unit. Generally the difficulty lies in transporting heavy components significant distances in a single, non-looped, flowline laterally, e.g. to the location of the subsea wellhead, manifold or production centre, from the bottom of the riser section, where there is a relatively sharp bend section connecting the riser section and flowline.

Figure 14 is a first embodiment designed to solve these problems. It uses a tractor unit powered by VARRIS power supply coiled tubing 19 to install a tool or other down-riser operating device.

A tractor unit, as used for automated drilling using coiled tubing for down-riser deployment is powered by hydraulic fluid provided from VARRIS power supply tubing 19. The tractor tows/pushes the VARRIS pump 11 until it reaches a predefined location in the riser 4 or flowline 1 determined by the length of power supply tubing 19 inserted into the riser/flowline. Once at its location, pressure set valving within the tractor is used to set the packer that locates the VARRIS tool in position (e.g. as a pump), and the tractor function is disabled. Power fluid is now directed to the VARRIS pump which operates in the manner described in preceding embodiments.

To retrieve the pump, pressure set valving within the pump disconnects the packer. The pump and its tractor can now be retrieved by applying a tension on the power supply tubing from a tensioner located at the riser tubing head entry point. If needed, additional drive is available by controlled operation of the tractor in the reverse direction.

A specific implementation of this method will be described below with reference to Figures 14a, 14b and 14c.

A second technique to be described with reference to Figures 15a, 15b and 15c uses the principle of the VARRIS pump which provides self drive along a flowline.

In this second method, the VARRIS pump is provided with drive fluid during installation. This drives the pump and produces a low pressure area in front of the pump relative to the pump discharge. This is maintained as a differential pressure across the pump by virtue of a lip seal type gland (the towing gland) which permits the force generated by this differential pressure to pull the pump and VARRIS power supply tubing along the flowline. A controlling back tension is provided by the tensioner located at the riser's tubing head. Once at its location pressure set

valving within the pump is used to set the packer that locates the VARRIS tool in position in common with previous descriptions. Retrieval of the pump is achieved by deactivating the packer as described above and applying a tension on the power supply tubing from the tensioner described above.

Reference is now made to a specific implementation of the first method shown in Figures 14a, 14b and 14c, where the installation distance from the riser base exceeds the ability of the coiled tubing deployment drum 7, or derrick system 160, to place the VARRIS components into position, due to buckling of the tubing 19. This problem is overcome by a tractor unit 158 used to haul the VARRIS components (e.g. pump assembly 11, and VARRIS tubing 19) into position.

The function of the tractor unit 158 is to drive the pump assembly 11 down-riser and also to retrieve the pump assembly to the top of the riser, for repair or maintenance. The tractor unit has a drive arrangement which comprises essentially a forward pair and a rearward paid of inflatable grippers 158a, 158b mounted on respective parts of a telescopic chassis. On inflating the forward grippers 158b so as to grip the inner surface of the riser wall and deflating the rearward grippers 158a so as to release them from riser inner surface, the rear telescopic part is retracted relative to the now stationary forward one. Then, the forward grippers 158b are deflated, the rearward ones 158a inflated and the front telescopic part extended forwardly relative to the rear part. By repeating the above sequence of operations, the tractor unit can advance insider the riser. With appropriate action on the grippers and telescopic chassis in a corresponding fashion, the tractor unit 158 can also retreat in the opposite direction within the riser.

On completion, the tractor unit 158 may either remain in position as the grippers are arranged so as not to seal the annulus, allowing fluids to flow past it via the annulus 105, or it may form a permanent part of the packer 10. Retrieval of the system follows disengagement of the packer 10, and application of tension to the VARRIS tubing 19 via the dispensing drum 7 located at the tubing head 122.

A preferred method of operation will now be described, starting with installation. The system as described above according to various disclosed embodiments is installable from the tubing head 122 down to a remote subsea facility (e.g. subsea manifold processing centre/junction 156, or subsea well 157), by use of a tractor unit 158, which derives its power from the VARRIS power supply tubing 19, differential head across the tractor unit 158 or electrical supply umbilical 164. It is envisaged that the most likely power option for the tractor unit 158 will utilise hydraulic drive supplied via the VARRIS power supply tubing 19.

The VARRIS power supply tubing 19, may be either of open loop (i.e. single coiled tubing) or closed loop (coaxial tubing format). The pump assembly 11, will correspondingly be of open loop (i.e. power fluid exhaust into the product in the flowline 1), or closed loop (power fluid exhaust and returned to surface via coaxial return line).

Once in its operating position the tractor unit drive is disengaged and the packer 10 is set, so as to engage with the inner wall surface of the riser. The grippers 158a, 158b on the tractor are deflated/retracted such that maximum local annulus area can be achieved for the packer 10. It is envisaged that for the powered option these grippers 158a, 158b will not encompass the full cross section of the annulus 105 in a single plane at right angles to the major axis of the flowline, but will occupy sectors of the annulus 105 spaced at intervals along the major axis. This provides a fluid path between both sides of the tractor unit for the passage of product or other fluids in the flowline 1.

The VARRIS power supply tubing 19 may be deployed from a coiled tubing drum 7 (Figure 14a), or derrick 160 (Figure 14c). Hydraulic power fluid is provided to the VARRIS power supply tubing 19 via at least one integral coupling 161, for the coiled tubing drum 7 with its pipe straightener 135, or via removable power fluid hose 162 for the derrick method.

Retrieval of the down-riser operating device will now be described. Following disengagement of the packer 10, the VARRIS components are retrieved by

applying a hauling tension via the tensioner 163, located above the riser tubing head 122. For the closed loop power fluid supply method, additional retrieval effort may be achieved by reversing the turbine drive fluid and supply fluid routes and re-energising the tractor unit 158, to operate in the reverse direction. This would be performed under limited input flow to prevent buckling of the VARRIS tubing.

An example of the second method referred to above will now be described (see Figures 15a, 15b and 15c) in which the system is as described above but which operates to haul the VARRIS components into place by using differential pressure generated across the pump 11. This is achieved by driving the pump 11 via the power supply tubing 19, thus providing the motive force.

The method of operation for a closed loop option according to Figures 15a, 15b and 15c is as follows. For the closed loop option the drive fluid returns to the tubing head 122 via the coaxial return of the VARRIS power supply tubing 19. Thus, there is at most very minor net addition of fluid into the riser annulus 105. Differential pressure across the pump assembly 11, and towing gland 166, is generated by circulation of drive fluid that drives the pump 11, thus displacing fluid from the flowline 1, upstream of the pump 11 and creating a low pressure zone relative to the pressure in down stream annulus 105. This differential pressure energizes the towing gland 166 forming a sliding seal and the resulting differential pressure on the pump casing and towing gland 166, provides the motive force to haul the system into position.

For retrieval, the equalisation of differential pressure, or a differential pressure acting in the opposite direction de-energises the towing gland 166, and enables the VARRIS components to retrieved by applying a hauling tension via the tensioner 163, located above the riser tubing head 122.

The method of operation for an open loop option will be described. This option is the same as shown in Figures 15a-15c, except that no return hydraulic flow line is provided in power supply tubing 19. For the open loop drive fluid option both the

drive fluid and any liquid displaced upstream of the pump are dumped into the annulus 105. The higher pressure in the annulus 105 relative to the lower pressure upstream of the pump cause the towing gland 166, to be biased to seal. The resulting differential pressure on the pump casing and towing gland provides the motive force to haul the system into position. The net additional fluid provided by the drive fluid entering the system is drawn off at the tubing head 122. For retrieval, the lack of differential pressure across towing gland 166 (achieved by the leaky nature of biased check valve 125) enables the VARRIS components to be retrieved by applying a hauling tension via the tensioner 163, located above the riser tubing head 122.

Another application of VARRIS is to the removal of scale/wax.

In a single flowline with no circulation capability, or where a blockage (partial or total) prevents establishment of a circulation route, it is not possible to access or clean along the flowline unless the device providing this function is self-powered. Also if the build up on a flowline or riser wall comprises hard scale, this is likely to need to be removed by active means (e.g. a cutter) rather than passive means (scraper pig). At present, available active cutting means are of very limited effectiveness.

In keeping with the basic configuration of running internal service tools on coiled tubing as described in previous VARRIS examples, a turbine driven cutter/brush module complete with a low throughput high internal clearance pump 11, is located at the end of the VARRIS power supply tubing. Using similar operating principles to those of the embodiment of Figure 15a above, the cutter which is forward of the pump is driven by a common shaft/reduction unit. As above a differential pressure is achieved across the tool which provides motive force to pull the cutters along the flowline. Cutting retrieval may be achieved by a variety of methods:-

1. Where there is no flow in the flowline either from production or from open loop power fluid discharge, the cuttings can be retrieved as the tool is hauled back to the riser entry point;
2. Where there is no flow in the flowline, cuttings are known to be pulverised, and a closed loop system is used, the pump can ingest the cuttings and deliver these back to the surface via the closed loop return line;
3. Where there is an open loop return, the cuttings are driven back to the surface using the power fluid discharge; and
4. Where it is required to perform the cleaning operation under conditions where product flows continuously (i.e. continuous production), the VARRIS tubing and its cutting tool are run from the tubing head using a conventional coiled tubing lubricator/injector assembly. Cuttings retrieval would use any of the above options 1 to 3.

Although a cutter is mentioned for cleaning the inside of the riser, other forms of cleaning device e.g. a brush or brush cutter, can be used. The type of cleaning device selected will depend on how harsh or gentle the cleaning action needs to be.

The system principle is similar to that described above for previous embodiments and uses the power turbine or electric motor drive to rotate a cutter/brush module 171 (see Figures 16a-d), for the purpose of cleaning deposits from the inside wall of a pipeline 1 or riser 4. Insertion and retrieval uses the principles described above. The previously described VARRIS combination of closed and open loop systems are applicable for the case when it is required to travel within the pipeline whilst cutting and simultaneously boosting flow. Hence, when not actuated the pump packer is required to be a sliding fit within the pipeline/riser inner wall and a small percentage of leakage or forward flow reflux from the discharge of the pump back to its suction is permissible. In addition to cutting whilst there is a flow in the pipeline, it is possible to cut under no-flow conditions by providing a transport fluid down the annulus 105, to the vicinity of the cutters (or via the VARRIS power supply tubing 115). This fluid is returned to the surface with the ingested cuttings 172, through the pumping section 113a, and from there via the return annulus of

the VARRIS power supply tubing. A variation on the transport fluid concept is to provide this fluid in the form of excess turbine drive, the surplus transport fluid being dumped into the vicinity of the cutters 171, and thence returned to the surface via the annulus 105. In all cases the cutter/brush module 171, may be in the form of a rigid extension of the VARRIS turbine shaft or pump shaft or a dedicated remote unit driven by extensions of the shaft of the VARRIS turbine 113b. A gearbox 173 may be used to optimise the cutter speed.

Various embodiments will now be described.

A closed loop production mode cleaning apparatus is shown in Figure 16a. In this mode, the propulsion drive is provided principally by the pressure differential over the towing gland 166, which is a sliding sealing fit in the riser. The rotating cutter 171 will generally produce a pressure differential across it which will tend to draw the tool down inside the riser 4 but its driving effect is small compared with that produced by the pumping unit 113a/packer 166.

The power turbine drive fluid, both supply and return, is entirely contained within the co-axial coiled tubing 19 attached to the end of the turbine 113b. The boosted production flows separately to the surface via annulus 105.

On the return movement the boost power may be reduced to allow the well fluid pressure acting on the towing gland 166 to assist the pull of the coiled tubing.

In open loop production mode cleaning (Figure 16b), a single VARRIS hydraulic power supply tubing 19 is utilised to power the turbine and provide traction for the tool. The turbine exhaust is commingled with the boosted flow and returns to the surface via annulus 105.

In shutdown mode using annular cutting fluid flow (Figure 16c), the transport fluid 175 for the cuttings 172 is pumped down annulus 105 to the pump inlet where it picks up the cuttings and is boosted in the pump to commingle with the turbine exhaust and thence to the surface via the VARRIS power supply tubing 19. In this

embodiment, traction is provided solely by the cutter or with thrust assistance from the power supply tubing 19. Therefore, the cutter has to be designed such that its rotating cutter blades produce sufficient traction as required.

Figure 16d shows schematically an embodiment using shutdown mode co-axial tubing cutting fluid flow. In this mode, excess turbine drive fluid is provided. As shown in the Figure, the excess is bled off (at 134) into the vicinity of the cuttings and provides the fluid transportation system for the chipping via annulus 105 to the surface. As in Figure 16c, the movement within the flowline/riser is provided by the thrust/pull forces applied by the cutter brush module and VARRIS power supply tubing. In this embodiment, moreover, no pumping section is provided, so that the turbine 113b drives the cutter 171 directly.

In the embodiments according to Figures 16a and 16b (as in the preceding embodiments having sliding seals) the sliding seal does not have to provide complete sealing with the inner surface of the riser wall. Rather, some leakage is permissible and even desirable so as to minimise sliding friction.

Furthermore, the pipe will usually be a rigid pipe drawn from a coil on a drum, using a pipe straightener and tensioner to deploy straightened pipe. However, it could be a flexible pipe where a sufficient differential pressure can be generated by the tool itself.

Although the boost/lift pump in Figures 16a-c is a hydraulic pump, it could instead be an electric pump.

It is also possible to use the described systems for adjusting the position of the pump, heater or gas injector within the riser. For example, if the component in question is to be moved to a position nearer the top of the riser, it would be retrieved completely from the riser, disconnected from the pipe, an appropriate length of pipe cut off the end, and the component re-connected and re-deployed down the riser in the new position. If, alternatively, the component is to be lowered, then it would be withdrawn from the riser, disconnected from the pipe, an

additional length of pipe attached to the end of the main pipe, the component re-attached and then driven back down into the riser to the final, required position.

It will be appreciated that the described embodiments all take advantage of existing developed technology for dispensing (laying) rigid pipes, by using at least one rigid pipe to carry a pump, heater, gas injector, cutter or other equipment and deploy it at a desired position within the riser by driving the or each pipe downwardly into the riser. Furthermore, since the top end support for the riser, which can be an attendant service vessel or a submerged buoyancy unit, is positioned at or in the vicinity of the sea surface, the pump, heater, gas injector or cutter can be retrieved to the top end support, where it is readily accessible to crew members from overhead, for replacement or maintenance purposes.

The attendant vessel may itself include a production tower for producing hydrocarbon fluid from a well supplying the flowline leading to the riser. It is also possible for the top end support to be a drilling platform anchored on the sea bed.

In the Figures, individual items are provided with reference numerals according to the following Table:

1	flowline
2	sea bed/mud line
3	homogeniser (optional)
4	riser
5	sea surface
6	support vessel
7	powered drum
8	pipe lubricator/injector (lubrication element optional)
9	crane
10	packer
10a	seal
11	HSP

11'	ESP
11 <sub>1</sub>	inlet for HSP
11 <sub>2</sub>	outlet for HSP
11 <sub>3</sub>	hydraulic fluid inlet
11 <sub>4</sub>	hydraulic fluid outlet
12	supply pipe
12a	supply pipe
13	return pipe
13a	return pipe
14	pump
15	heater
16	power supply cable
18	heater
19	coiled pipe
20	buoyancy unit
21	riser base
22	take-off hose/flexible hose
23	gooseneck pipe
24	maintenance stack
25	Y junction
26	preventer valve
27	preventer valve
28	Y junction
29	coaxial stub
30	heater
31	electric pump
32	electric pump
33	switchgear
34	power supply line
35	power connector
36	injector/poker
40	valve (on-off)

41	valve (on-off)
42	valve (on-off)
43	hose/hydraulic fluid
44	connecting line
45	isolator/hydraulic pipe
46	connecting line
47	isolator/hydraulic pipe
48	hose
49	auxiliary pipe
50	pressure cap
100	inflation line/umbilical
101	product in the flowline
103	outer tubing
105	annulus between the riser/flowline and the tubing
107	transition zone
108	separation zone
109	perforated tubing section
111	the upper annulus
112	gas outlet
113a	pumping unit
113b	drive turbine
113c	flexible coupling
114	annulus between outer tubing and inner tubing
115	power supply tubing
115a	power return tubing
116	pump entry point
117	pump exhaust
118	fluid return tubing
119	annulus between the inner tubing and the pump power supply tubing 115
120	tubing hanger
121	separated liquid exit

122	tubing head
123	Cyclone insert
124	tubing head
125	biased check valve (permits limited leakage)
126	riser evacuation port
128	main production valve
129	gas inlet valve
130	drive fluid exhaust valve
131	drive fluid inlet valve
132	pump located riser evacuation valve
133	annulus bypass valve
134	drive fluid bleed off
135	pipe straightener
141	composite riser
142	riser end termination
143	riser base/manifold spool
144	spacers (optional)
151	platform static hang off
152	rigid riser clamps
153	riser base bend
156	subsea manifold processing centre/junction
157	subsea well
158	tractor unit
160	derrick
161	coiled tubing drum integral supply couplings
162	removeable power fluid hose
163	tensioner unit
164	electrical umbilical
166	towing gland
171	cutter brush module
172	cuttings
173	gearbox

175	transport fluid
176	check valve

CLAIMS:

1. A system for raising production fluid from a source on the seabed, comprising:-

- a riser having an internal passageway for conveying said production fluid and having a first, lower, end for connection to or connected to the source;
- a top end support for supporting the riser at its second end at or in the vicinity of the sea surface; and
- an operating device mounted inside the riser for displacement within the riser between a first, operating, position in the riser remote from its second end, and a second, access, position, at the second end of the riser, so that the device is accessible for replacement or repair.

2. A system according to claim 1 and further comprising means for displacing the device in the riser between the operating and access positions.

3. A system according to claim 2, wherein the displacing means includes a pipe which extends within the riser and to a lower end of which the device is attached.

4. A system according to claim 3, wherein the device is an electric pump and an electric power supply cable for the device passes through the pipe.

5. A system according to claim 3, wherein said pipe is connected to supply fluid from the upper end of the riser down to the operating device.

6. A system according to claim 5, wherein a further pipe is provided within the riser and is connected to function as a return pipe for conveying fluid from the operating device to the upper end of the riser.

7. A system according to claim 6, wherein the supply and return pipes form a nested pipe arrangement.
8. A system according to claim 5, wherein the device is a hydraulic pump and the pipe is arranged to convey hydraulic fluid down to the pump, which is arranged to discharge the hydraulic fluid into the production fluid passing up the riser.
9. A system according to claim 6 or 7, wherein the device is a hydraulic pump, the supply pipe being arranged for delivering hydraulic fluid down to the pump and the return pipe being arranged for conveying hydraulic fluid from the pump back up the riser.
10. A system according to any one of claims 5 to 9, wherein means are provided for delivering heated fluid through the supply pipe for heating production fluid in the riser.
11. A system according to any one of claims 3 to 10, wherein said operating device comprises a heater for heating said production fluid in the riser.
12. A system according to any one of claims 3 to 11, wherein said operating device comprises a gas injector for introducing pressure gas into the riser when in said first position.
13. A system according to any one of claims 3 to 12, wherein the displacing means includes a pipe dispensing and retrieving apparatus on the top end support or an attendant service vessel, such apparatus comprising a rotatable pipe storage device on which the or each pipe is wound, a pipe straightener and drive means for the storage device, selectively operable for straightening a length of pipe and driving it downwardly into the riser to lower the device to said first position and to wind in the or each pipe to raise the device to said second position.

14. A system according to any preceding claim, wherein a pig introducing device is provided for introducing a pig into the riser at a position below the operating device when in said second position.
15. A system according to any preceding claim, further comprising a locating device which is mounted on the operating device, and is selectively operable for (i) engaging with the inner surface of the riser and (ii) disengaging therefrom so that the operating device can be repositioned in the riser.
16. A system according to claim 15, wherein the operating device is a pump and the locating device is a sealing device which is operable for both engaging and sealing with the inner surface of the riser so that the pump can pump production fluid in the riser from a low pressure side of the sealing device to a high pressure side.
17. A system according to claim 16, wherein the sealing device comprises a packer mounted on the pump and an inflatable sealing element operable for forming sealing contact with the inner surface of the riser.
18. A system according to any preceding claim, wherein in addition to said passageway for carrying the production fluid, a second passageway is provided in the riser for connection to a low pressure region in the vicinity of the upper end of the riser and means are provided for expelling production fluid from the first passageway to said low pressure region, so as to reduce the pressure in the first passageway to a lower value than that existing under interrupted or shutdown conditions, thereby inhibiting formation of solid hydrates in the first passageway.
19. A system according to claim 18, wherein the production fluid expelling means comprises a one-way valve providing fluid communication from the first passageway to the second passageway, a source of pressure gas operable for introducing gas under pressure to the first passageway to expel production fluid therefrom through the one-way valve, and means for venting the gas pressure in the first passageway to said region of lower pressure.

20. A system according to claim 18, wherein the production fluid expelling means comprises a pump in the riser arranged for pumping production fluid from the first passageway to the second passageway.
21. A system according to any one of claims 4 to 10, further comprising a cyclone separator mounted on the pipe for positioning within the riser and having inlet means for imparting swirl to production fluid entering the separator from the riser to effect separation of the fluid into a liquid-rich underflow and a gas-rich overflow, the pump being arranged to receive the separator underflow and pump it up to the top of the riser through said pipe.
22. A system according to claim 8 or 9 or any dependent claim thereof, wherein said hydraulic pump comprises a pump section, turbine section and a packer section, the packer section being articulated relative to the pump section.
23. A system according to claim 22, wherein the articulation comprises a universal drive coupling or a flexible coupling.
24. A system according to claim 22 or 23, wherein a heater is provided in the region of the hydraulic pump, the heater being arranged to be supplied by heating medium conveyed through said pipe.
25. A system according to claims 3 to 13, further comprising a traction device on the pipe operable for applying traction to the pipe to drive the operating device down inside the riser.
26. A system according to claim 25, wherein the traction device is selectively operable from the remote end of the pipe for applying traction to the pipe in either direction for lowering or raising the operating device.
27. A system according to claim 25 or 26 as dependent on any of claims 4 to 10, wherein a sealing device is mounted on the pump and arranged to provide a sliding seal with the inner surface of the riser, the pump being arranged to pump between a

low pressure and a high pressure side of the sealing device so as to generate a traction force for driving the down-riser pump longitudinally within the riser, the pump and sealing device together constituting said traction device.

28. A system according to any one of claims 3 to 13, wherein said operating device comprises a motor mounted on a lower end of the pipe and arranged to be powered by an electrical cable passing through said pipe, and a rotary cleaning device arranged to be driven by the motor.

29. A system according to claim 28 as dependent on any of claims 4 to 10, wherein a sealing device on the motor is arranged to form a sliding seal with the inner surface of the riser.

30. A system according to claim 29 as dependent on any of claims 4 to 10 wherein the pump is arranged to provide differential pressure between a low pressure side and a high pressure side of the sealing device.

31. A system according to claims 29 or 30, wherein the rotary cleaning device is arranged to generate a differential pressure between one side and the other side thereof when it is rotating.

32. A system according to any one of claims 28 to 31, wherein the cleaning device comprises at least one of a rotary cutter and a rotary brush.

33. A system according to any one of claims 1 to 32 wherein said riser has a lazy-S, steep wave or steep-S configuration.

34. A system according to any one of claims 1 to 32 wherein said riser has a substantially vertical compliant section, leading from the sea bed to the surface, a substantially horizontal section on the sea bed, and a bend section connecting the substantially vertical and horizontal riser sections.

35. A method of installing an operating device in a riser connecting a source of production fluid on the seabed to a top end support supporting the riser at or in the vicinity of the sea surface, comprising:-

- introducing the device into the riser at the upper end thereof; and
- driving the device downwardly into the riser to a desired operating position in the riser remote from its end at the top end support.

36. A method according to claim 35, wherein the device is attached to the lower end of a rigid pipe and the pipe is driven downwardly into the riser to displace the device to its desired operating position.

37. A method of maintaining or replacing a device installed in accordance with a method according to claim 36, comprising:-

- driving the pipe upwardly to raise the device within the riser to the top end support;
- removing the device from the riser; and
- disconnecting the device from the pipe, for maintenance or replacement.

38. A method according to claim 35, 36 or 37, wherein the operating device is a pump, heater or gas injector.

39. A method according to any one of claims 35 to 38, for adjusting the position of the operating device in the riser, wherein the device is retrieved from the riser through its upper end and disconnected from the pipe, an end section of the pipe is removed or a new section attached to its end to define a new length of pipe, and the device attached to the end of the new length of pipe and driven down the riser to its new operative position in the riser.

40. A method according to any one of claims 35 to 39, further comprising at least partially expelling the production fluid from the riser interior, so as to reduce the pressure acting there, in order to inhibit formation of solid hydrates in the production fluid flowing from the source under interrupted flow or shut down conditions.

41. A method according to claim 40, wherein a pump in the riser is used for at least partially expelling the production fluid.

42. A method according to claim 40, wherein gas is introduced under pressure into the riser to at least partially expel the production fluid and the gas pressure acting in the riser is reduced to a value lower than its initial value while preventing the expelled production fluid from returning to the space occupied by the gas.

43. A method according to claim 42, wherein a hydrate formation inhibitor is introduced into the riser along with the gas under pressure.

44. A method of raising production fluid in a riser from a source on the seabed whilst effecting separation thereof into gas-rich and liquid-rich constituents, comprising the steps of:

- installing a cyclonic separator in the riser using the method of any of claims 35 to 43;
- raising the production fluid in the riser,
- operating the separator to impart cyclonic separation of the production fluid into gas-rich overflow and liquid-rich underflow,
- directing the underflow downwardly within the riser to a lower location, and
- pumping the underflow at said lower location up the riser to the top thereof.

45. A method of inhibiting formation of solid hydrates in a riser carrying production fluid from a wellhead under interrupted flow or shut down conditions, comprising at

least partially expelling the production fluid from the riser interior, so as to reduce the pressure acting there.

46. A method according to Claim 45, wherein a pump in the riser is used for at least partially expelling the production fluid.

47. A method according to Claim 45, wherein gas is introduced under pressure into the riser to at least partially expel the production fluid and the gas pressure acting in the riser reduced to a value lower than its initial value while preventing the expelled production fluid from returning to the space occupied by the gas.

48. A riser system for carrying production fluid from a subsea wellhead, comprising a riser, a first passageway in the riser for carrying the production fluid, a second passageway in the riser for connection to a low pressure region in the vicinity of the upper end of the riser and means for expelling production fluid from the first passageway to said low pressure region, so as to reduce the pressure in the first passageway to a lower value than that existing under interrupted or shutdown conditions, thereby inhibiting formation of solid hydrates in the first passageway.

49. A riser system according to Claim 48, wherein the production fluid expelling means comprises a one-way valve providing fluid communication from the first passageway to the second passageway; a source of pressure gas operable for introducing gas under pressure to the first passageway to expel production passage therefrom through the one-way valve, and means for venting the gas pressure in the first passageway to a region of lower pressure.

50. A riser system according to Claim 48, wherein the production fluid expelling means comprises a pump in the riser arranged for pumping production fluid from the first passageway to the second one.

51. Apparatus for raising production fluid from a source on the seabed, the apparatus being arranged for positioning in or being positioned in, a riser having a first, lower, end for connection or connected to such source and a top end support

for supporting the riser at or in the vicinity of the sea surface, a fluid pump for positioning inside the riser, a pipe to a lower end of which the pump is attached, the pipe being positionable within the riser so as to extend within the same and support the pump in a selected position within the riser, and a cyclone separator mounted on the pipe for positioning within the riser and having inlet means for imparting swirl to production fluid entering the separator from the riser to effect separation of the fluid into a liquid-rich underflow and a gas-rich overflow, the pump being arranged to receive the separator underflow and pump it up to the top of the riser through said pipe.

52. A method of raising production fluid from a source on the seabed effecting separation thereof into gas-rich and liquid-rich constituents, comprising the steps of:

- raising the production fluid in a riser,
- imparting cyclonic separation of the production fluid into gas-rich overhead and liquid-rich underflow,
- directing the underflow downwardly within the riser to a lower location, and
- pumping the underflow at said lower location up the riser to the top thereof.

53. Apparatus for raising production fluid from a source on the seabed, comprising:

- a riser having a first, lower, end for connection or connected to the source,
- a top end support for supporting the riser as on in the vicinity of the sea surface,
- a down-riser operating device mounted inside the riser for displacement within the riser between a first, operating, position in the riser remote from its second end and a second, access, position at the second end of the riser, so that the operating device is accessible to an operator for replacement or repair,
- a pipe which extends within the riser and to a lower end of which the operating device is attached, and

- a traction device on the pipe operable for applying traction to the pipe to drive the operating device down inside the riser.

54. Apparatus for performing down-riser operations, the apparatus being arranged for positioning in or being positioned in a riser for raising production fluid from a source on the seabed, the riser having a first, lower, end for connection or connected to such source and a top end support for supporting the riser at or in the vicinity of the sea surface, the apparatus comprising a down-riser operating device for positioning inside the riser, a pipe for entering down within the riser and to a lower end of which pipe the operating device is attached, and a traction device on the pipe operable for applying traction to the pipe to drive the operating device down inside the riser.

55. Apparatus according to Claim 53 or 54, wherein the traction device is selectively operable from the remote end of the pipe for applying traction to the pipe in either direction for lowering or raising the operating device.

56. Apparatus according to Claim 53, 54 or 55, wherein the operating device is a down-riser pump and a sealing device is mounted on the pump and arranged to provide a sliding seal with the inner surface of the riser, the pump being arranged to pump between a lower pressure and a high pressure side of the sealing device so as to generate a traction force for driving the down-riser pump longitudinally within the riser, the pump and sealing device together constituting said traction device.

57. Apparatus for cleaning the inside of a riser comprising:

- a pipe extending or arranged for extending down within the riser;
- a motor mounted on a lower end of the pipe and arranged to be powered from an upper end of the riser; and
- a rotary cleaning device arranged to be driven by the motor.

58. Apparatus according to Claim 57, wherein a sealing device on the motor is arranged to form a sliding seal with the inner surface of the riser and the pump is

arranged to provide differential pressure between a low pressure side and a high pressure side of the sealing device.

59. Apparatus according to Claim 57 or 58, wherein the rotary cleaning device is arranged to generate a differential pressure between one side and the other side thereof when it is rotating.

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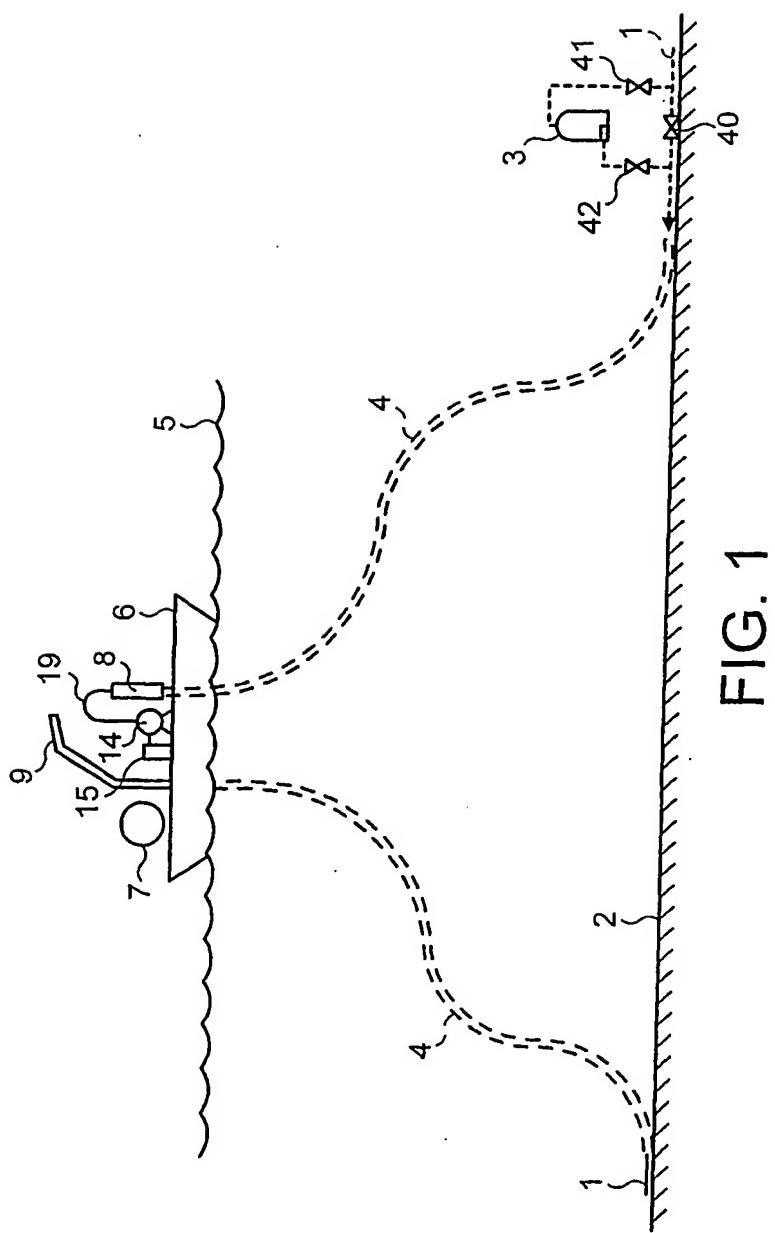
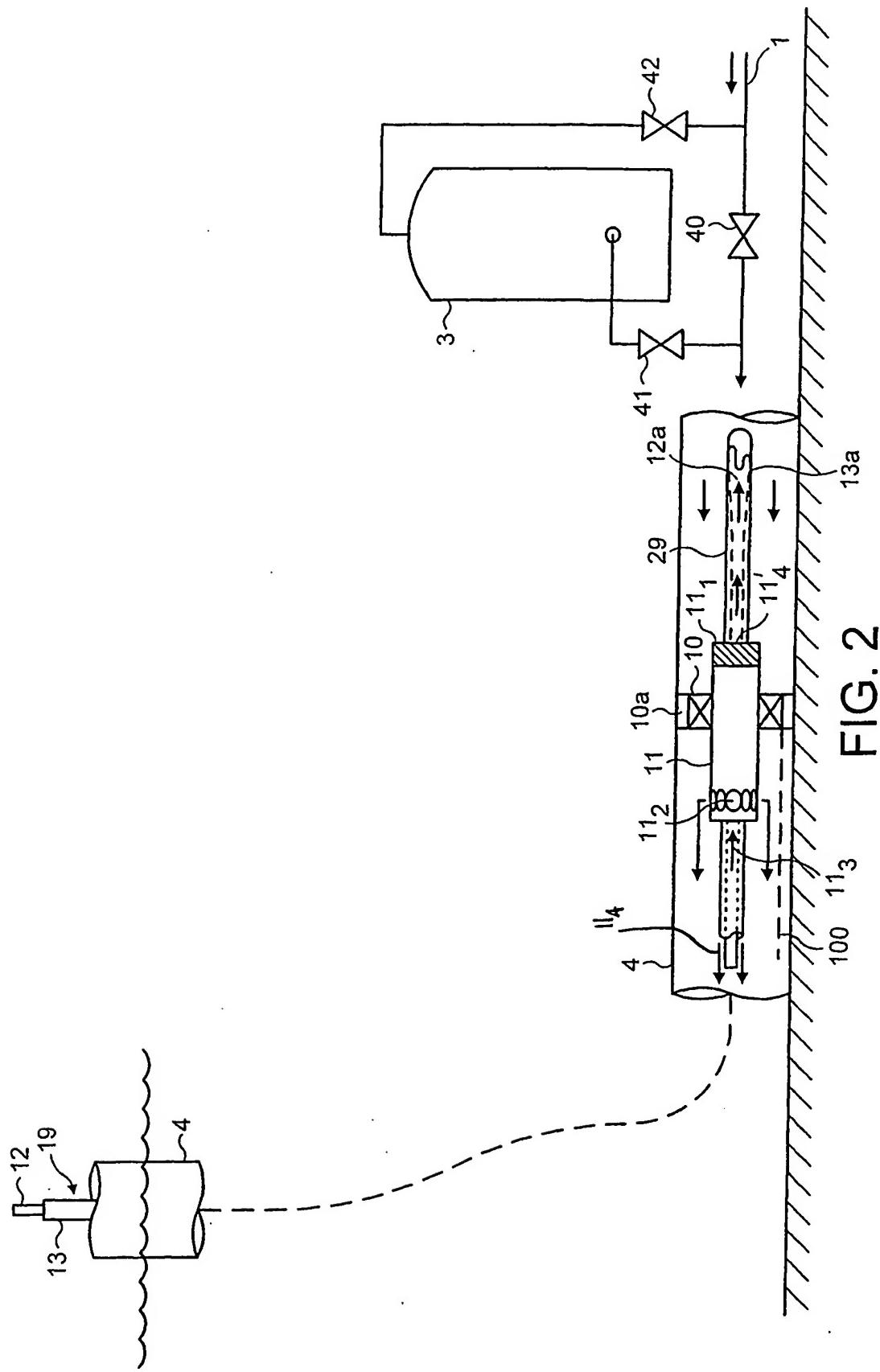


FIG. 1

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3 / 27

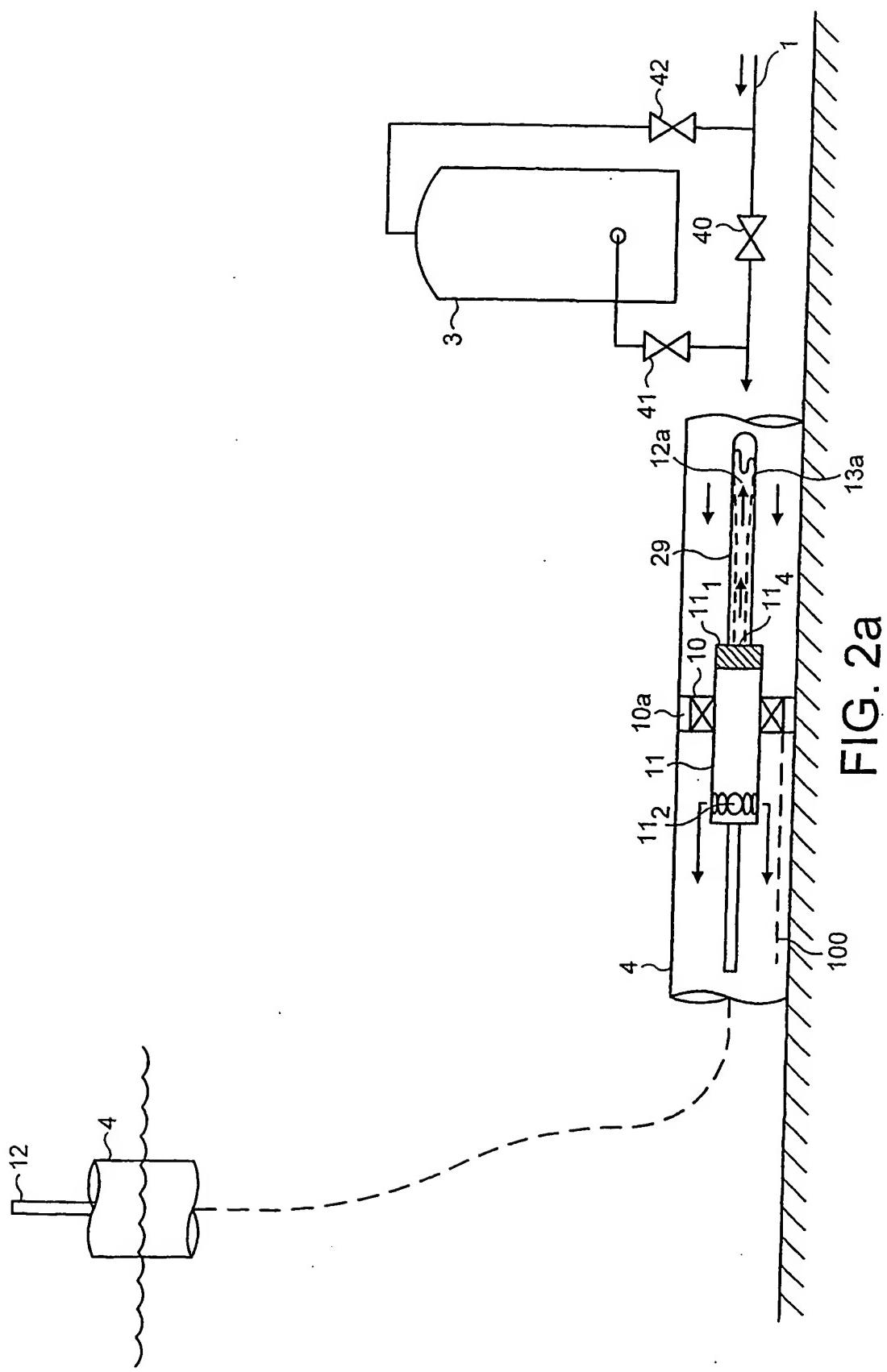


FIG. 2a

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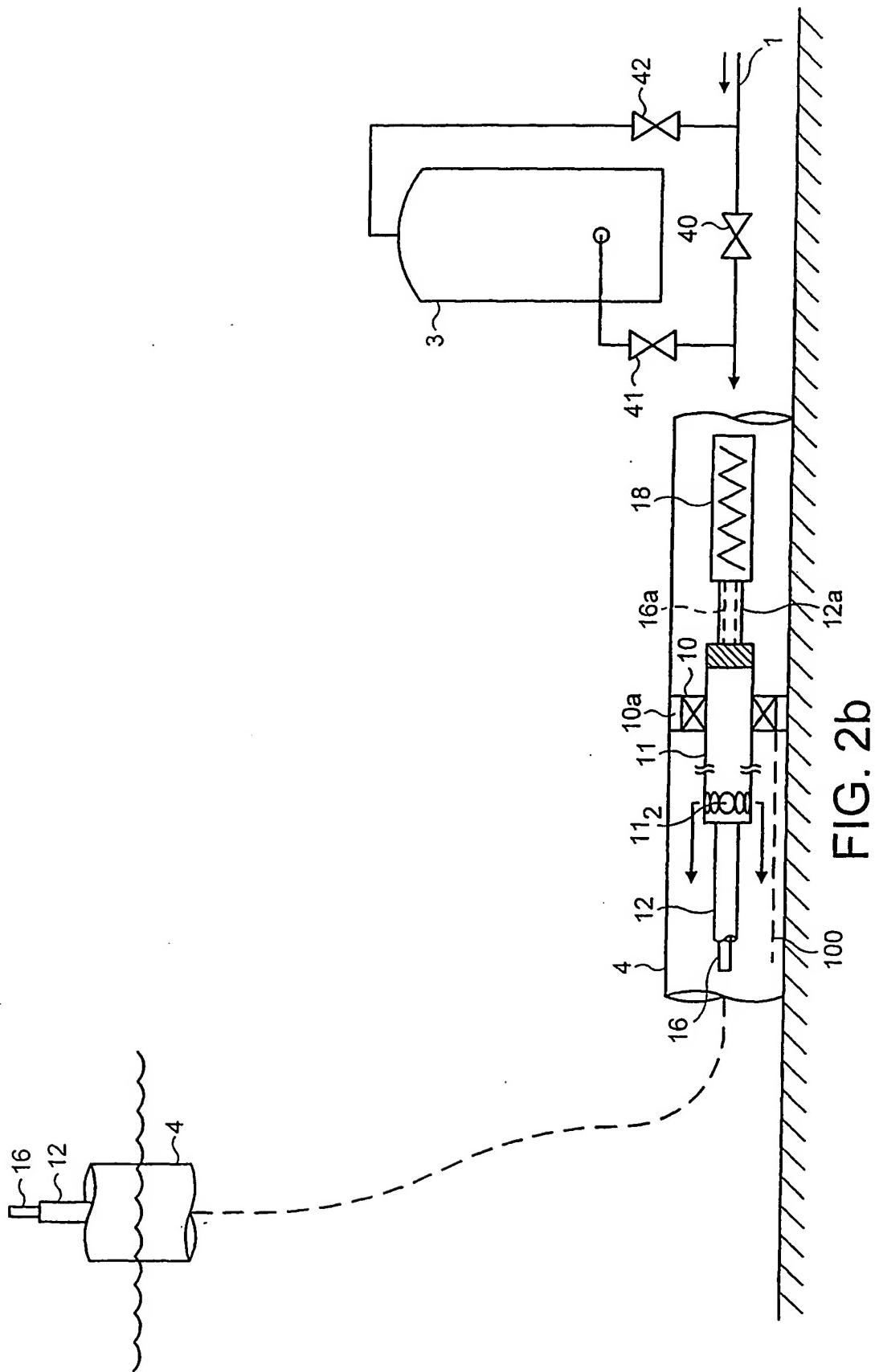


FIG. 2b

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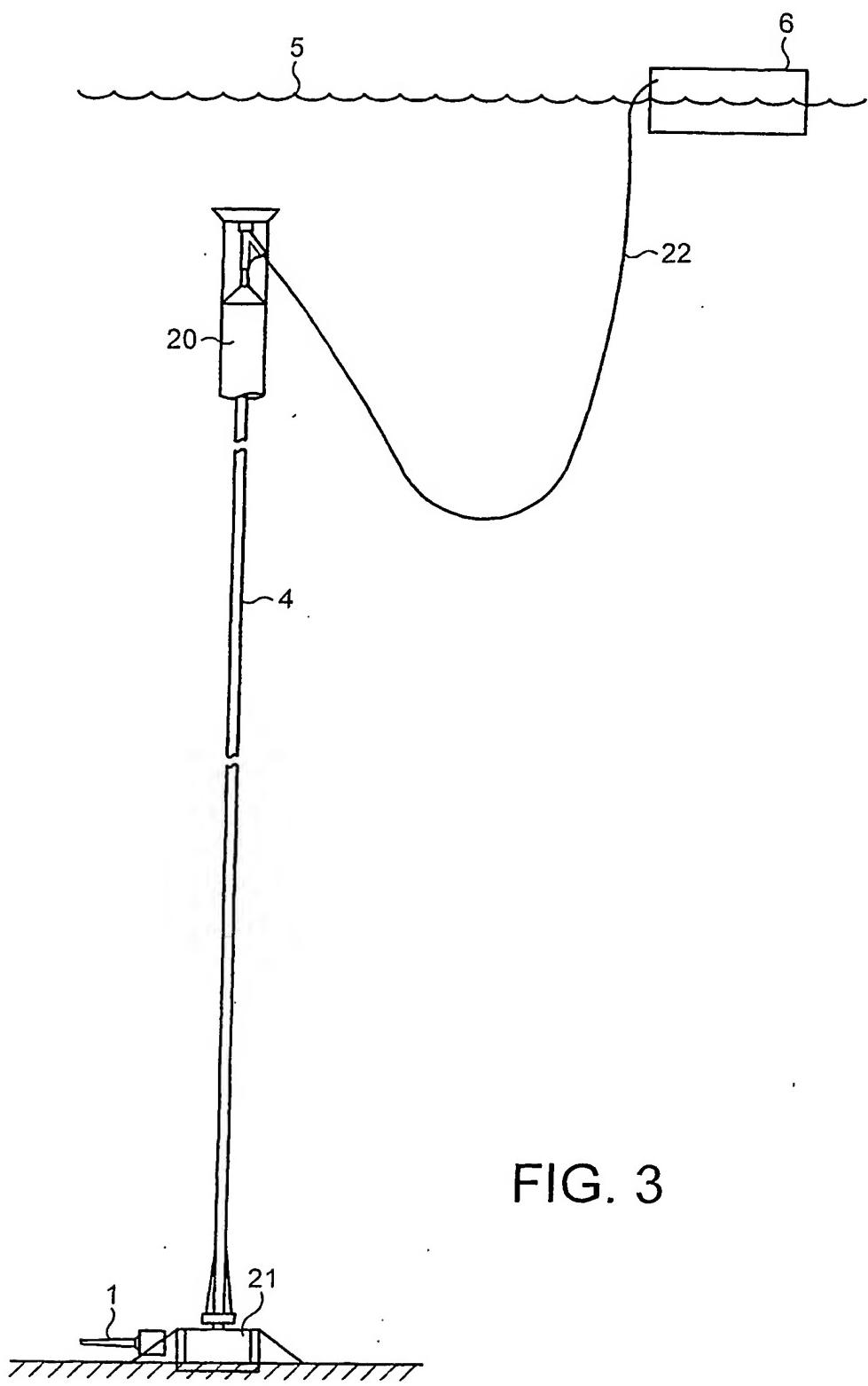
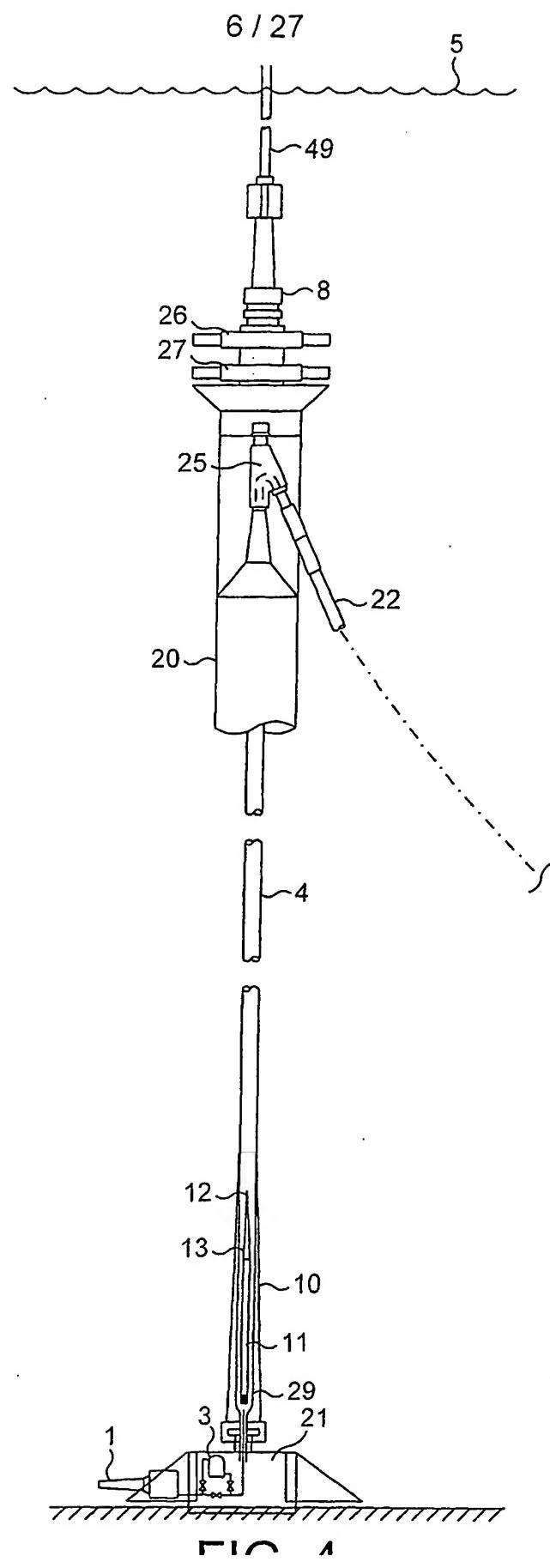


FIG. 3



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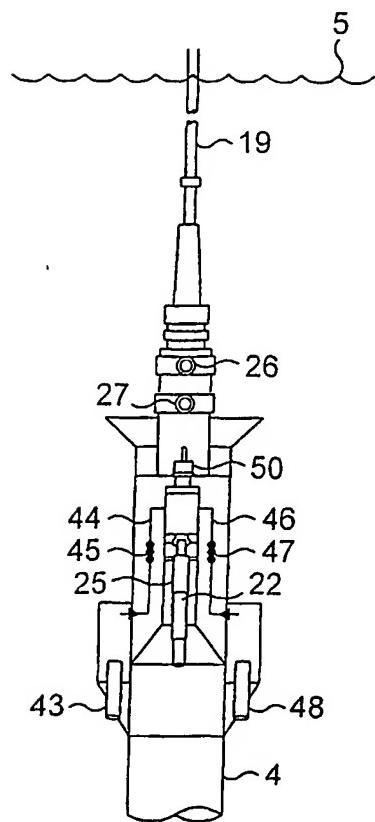


FIG.4a

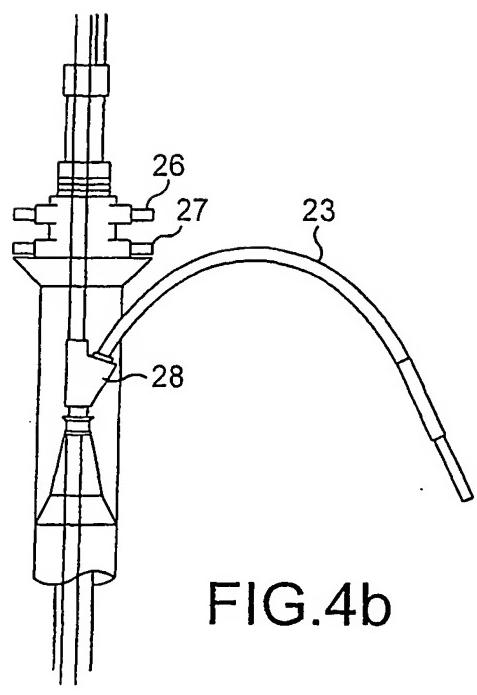


FIG.4b

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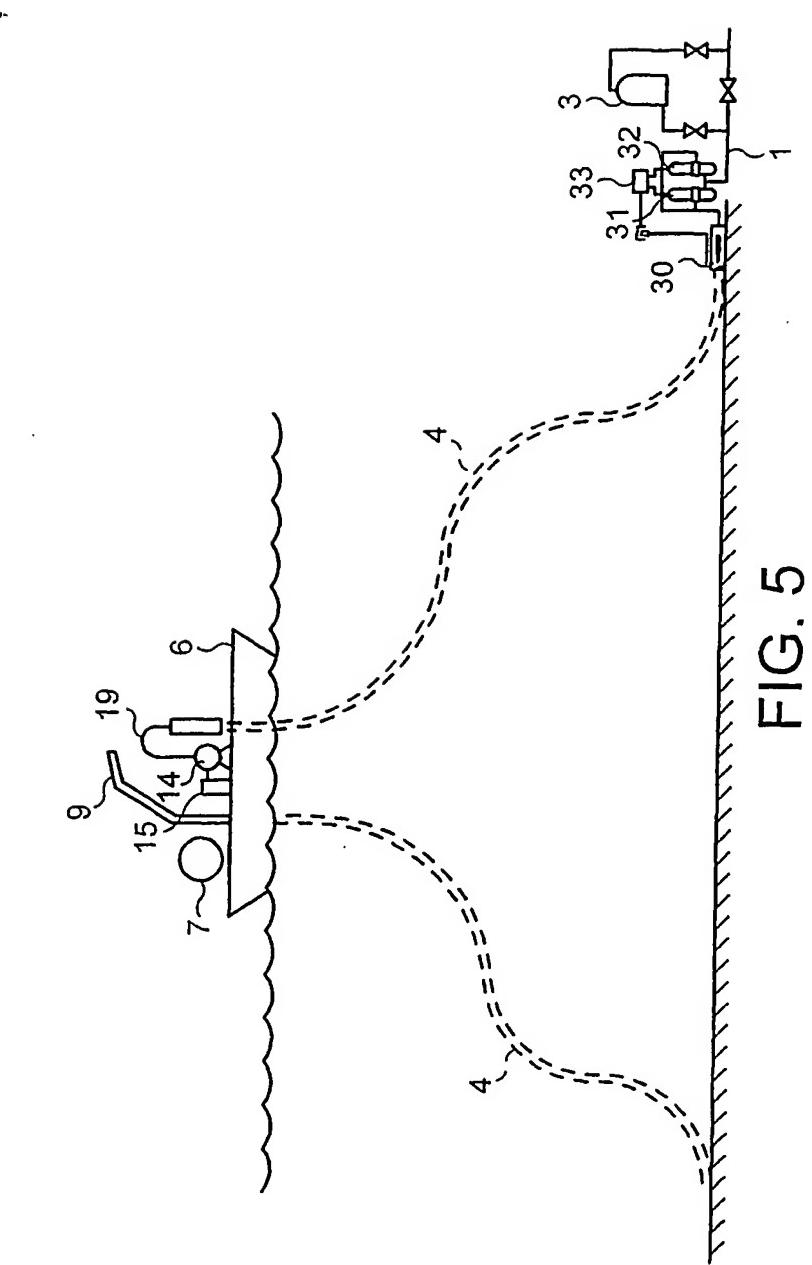


FIG. 5

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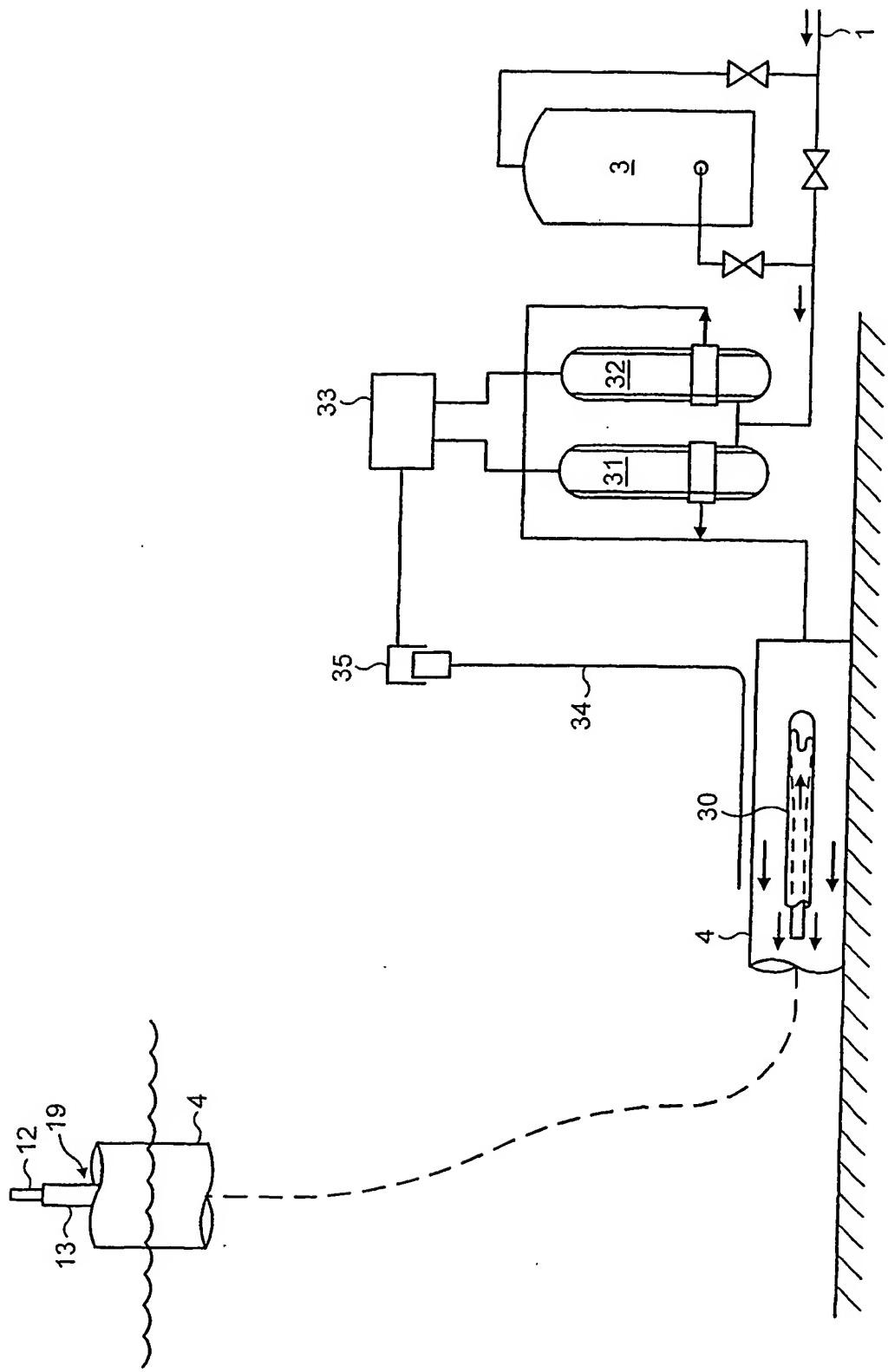


FIG. 6

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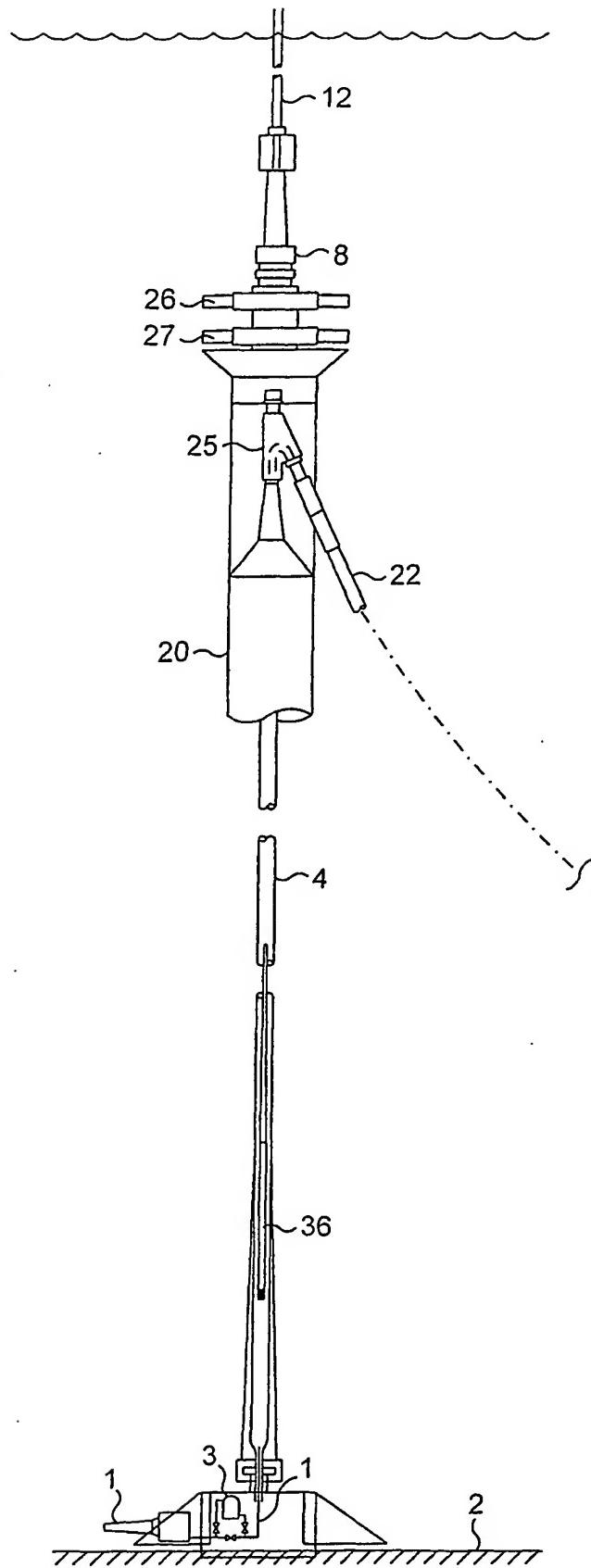


FIG. 7

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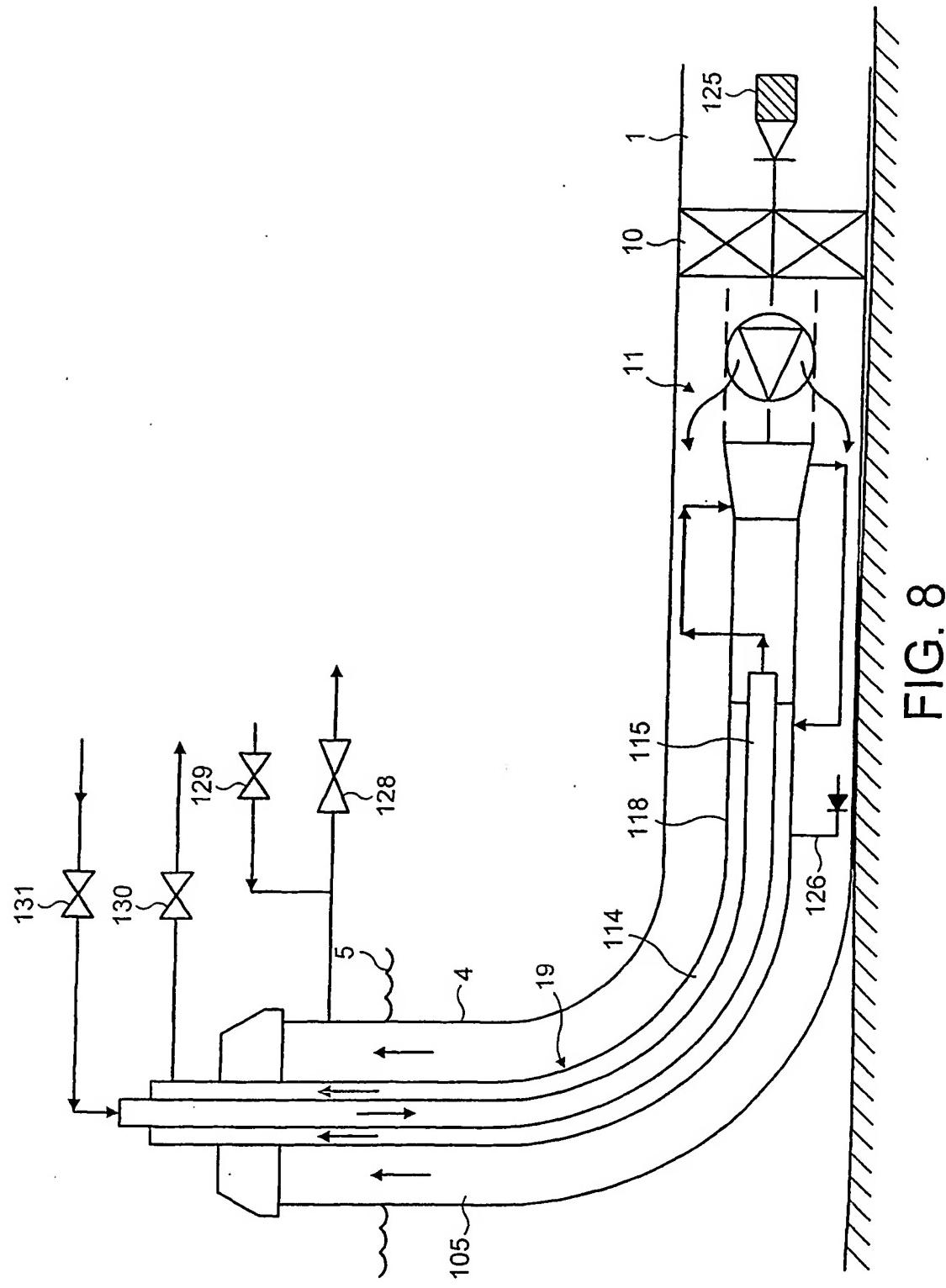


FIG. 8

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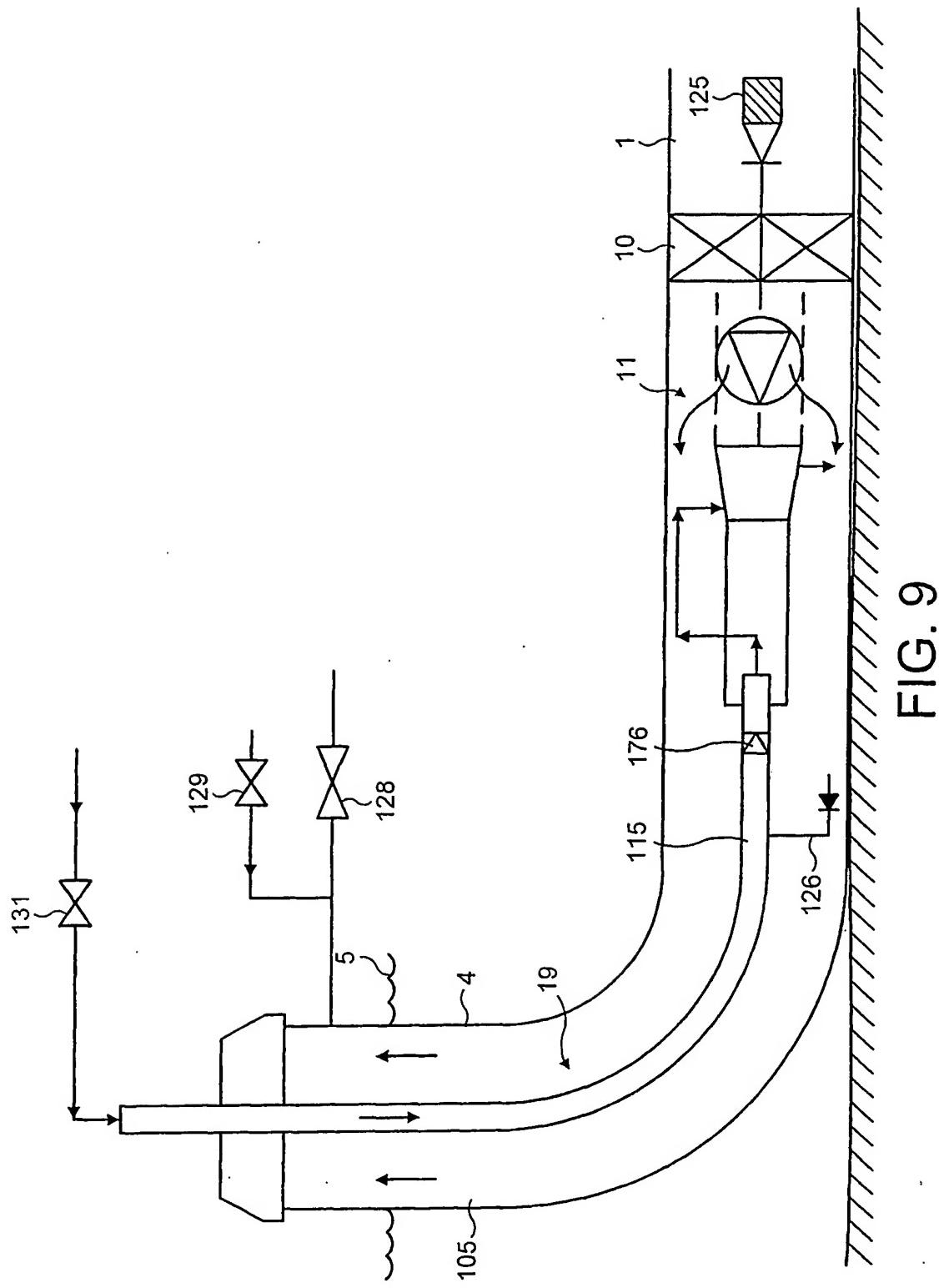


FIG. 9

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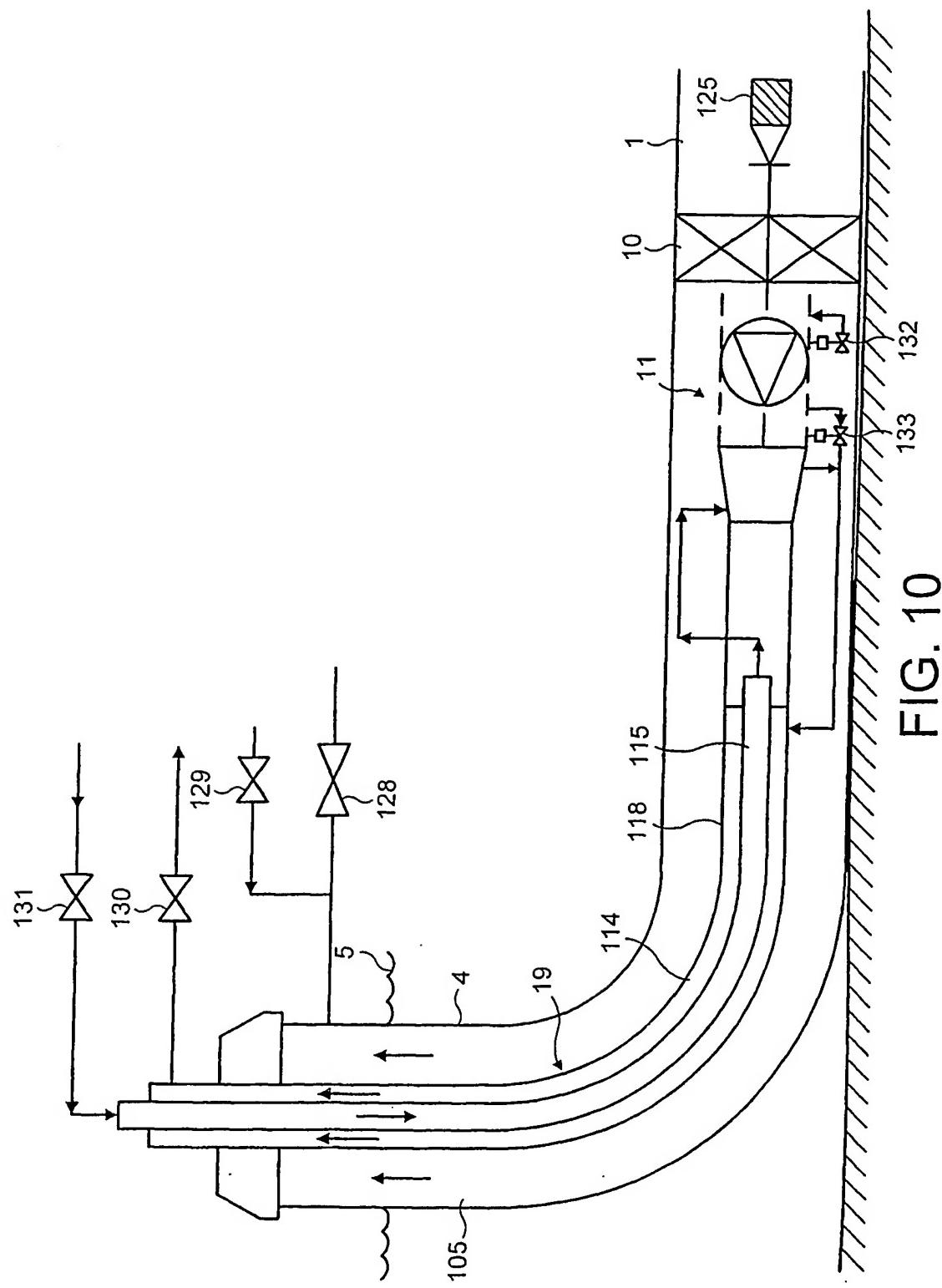


FIG. 10

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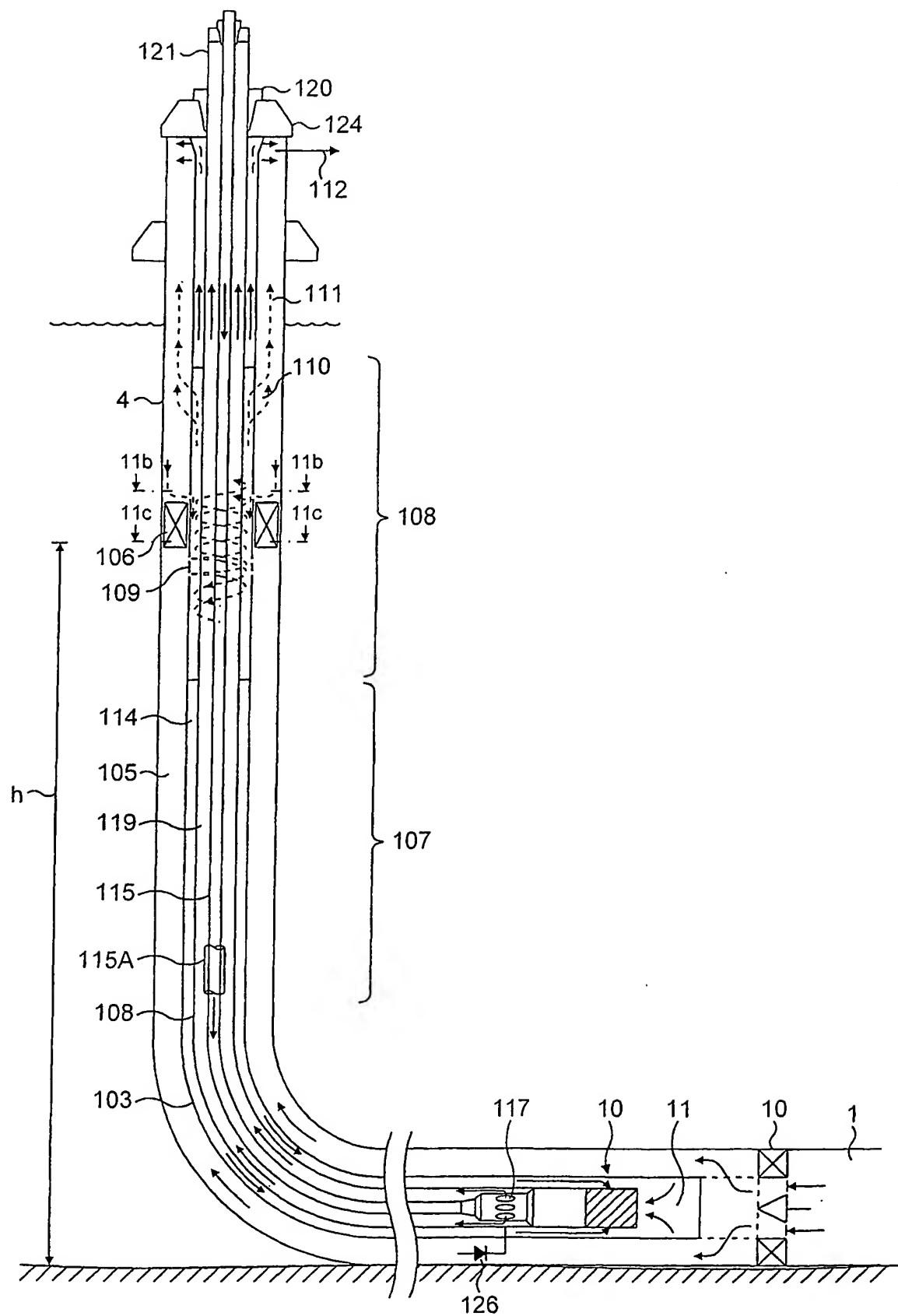


FIG. 11a

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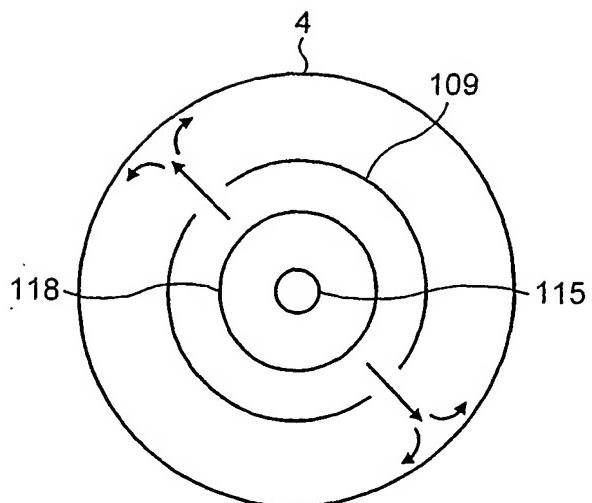


FIG. 11b

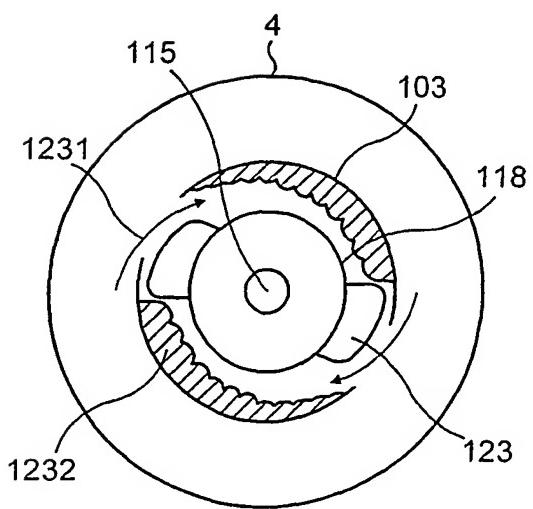
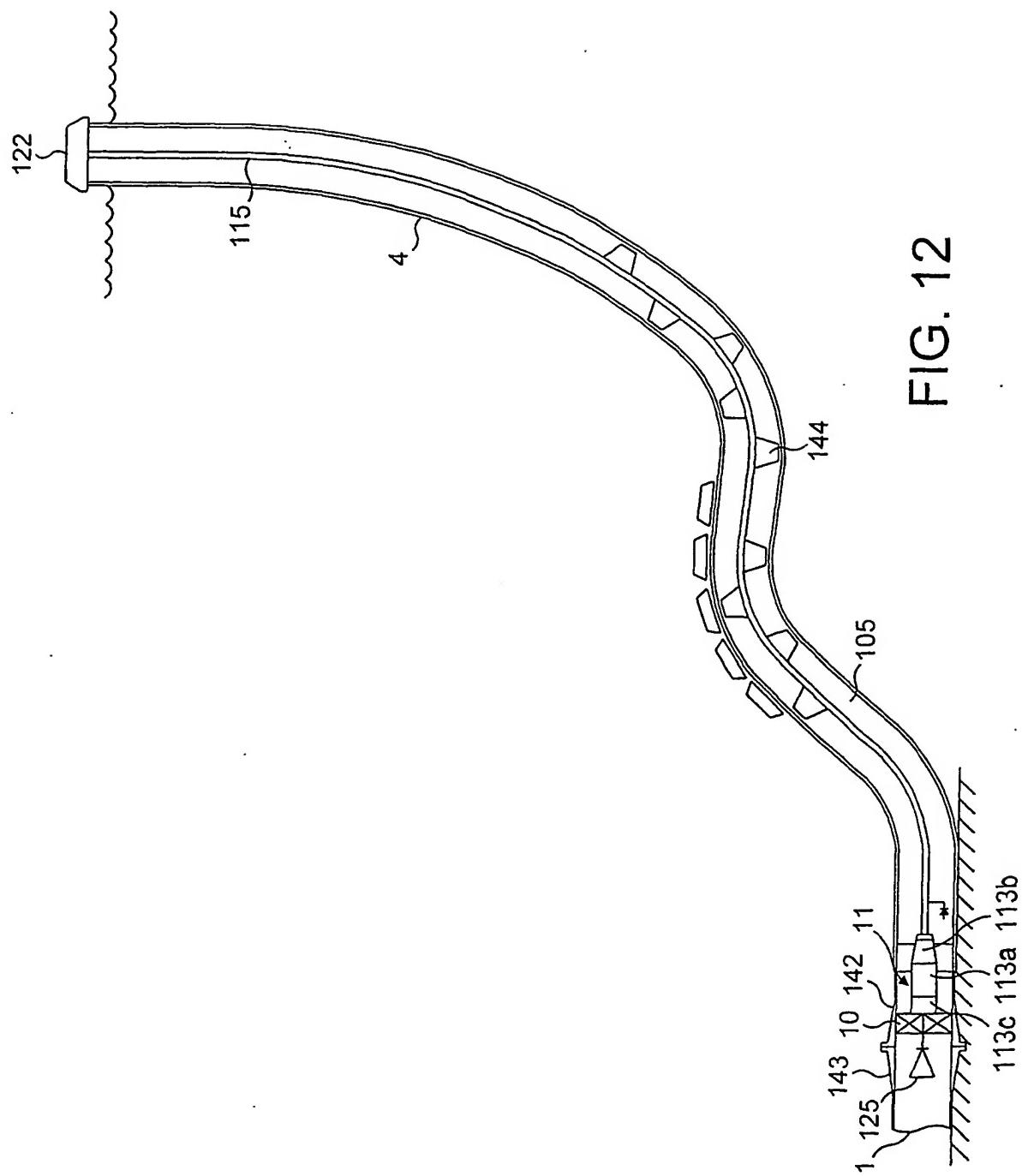


FIG. 11c

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FIG. 12b

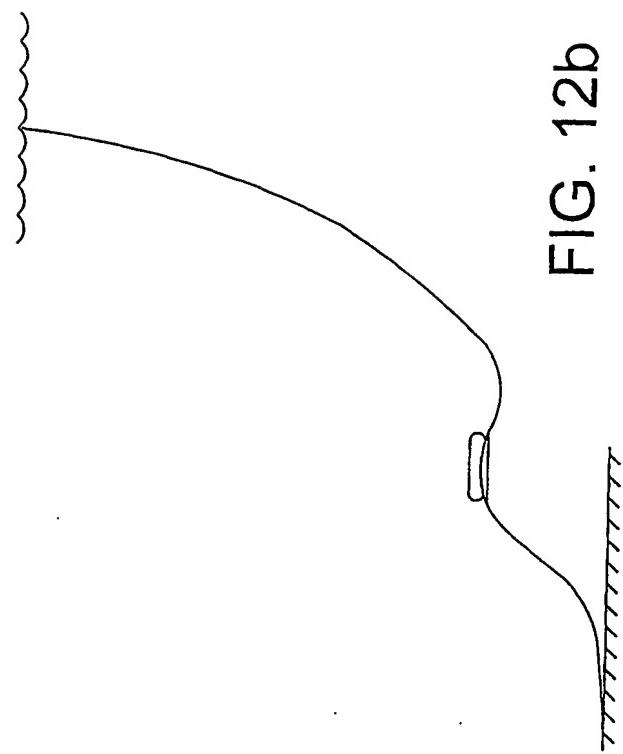
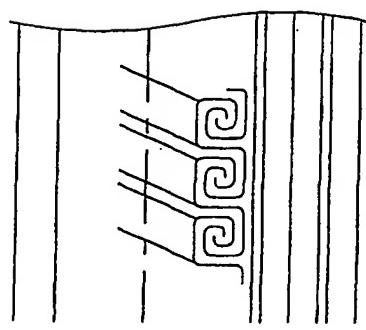


FIG. 12a



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FIG. 12d

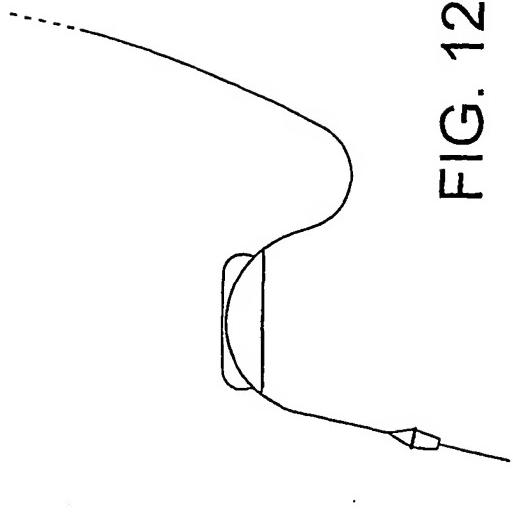
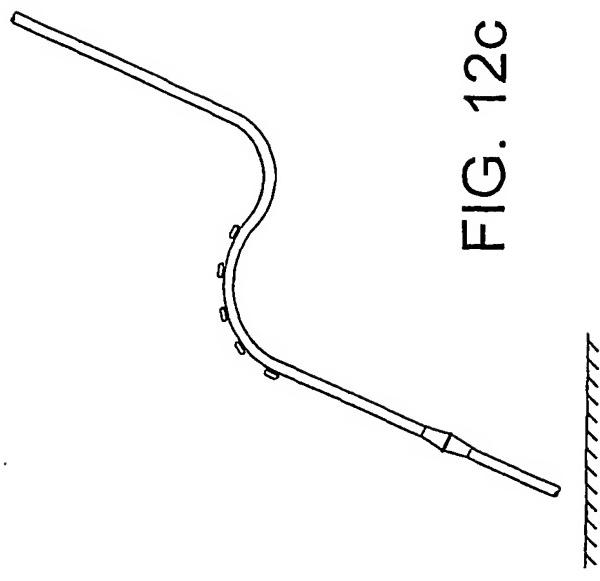


FIG. 12c



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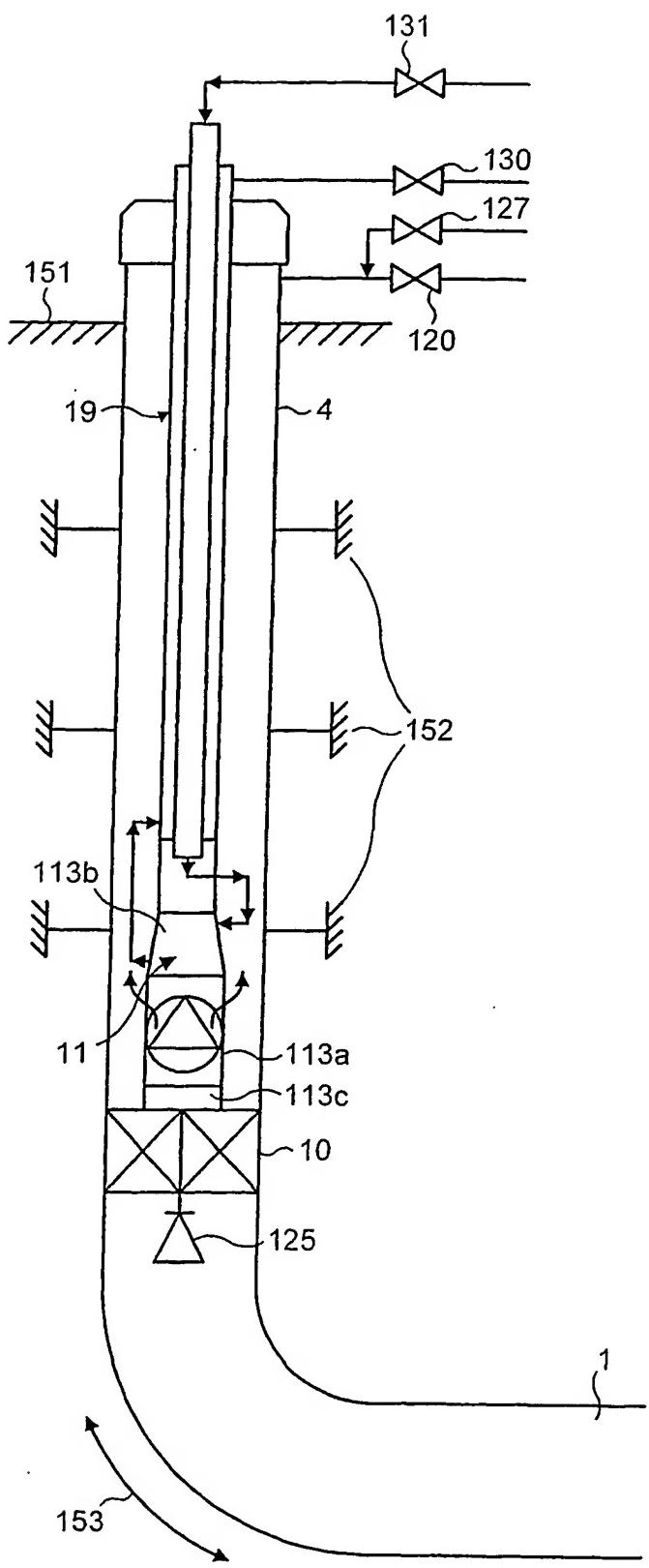


FIG. 13

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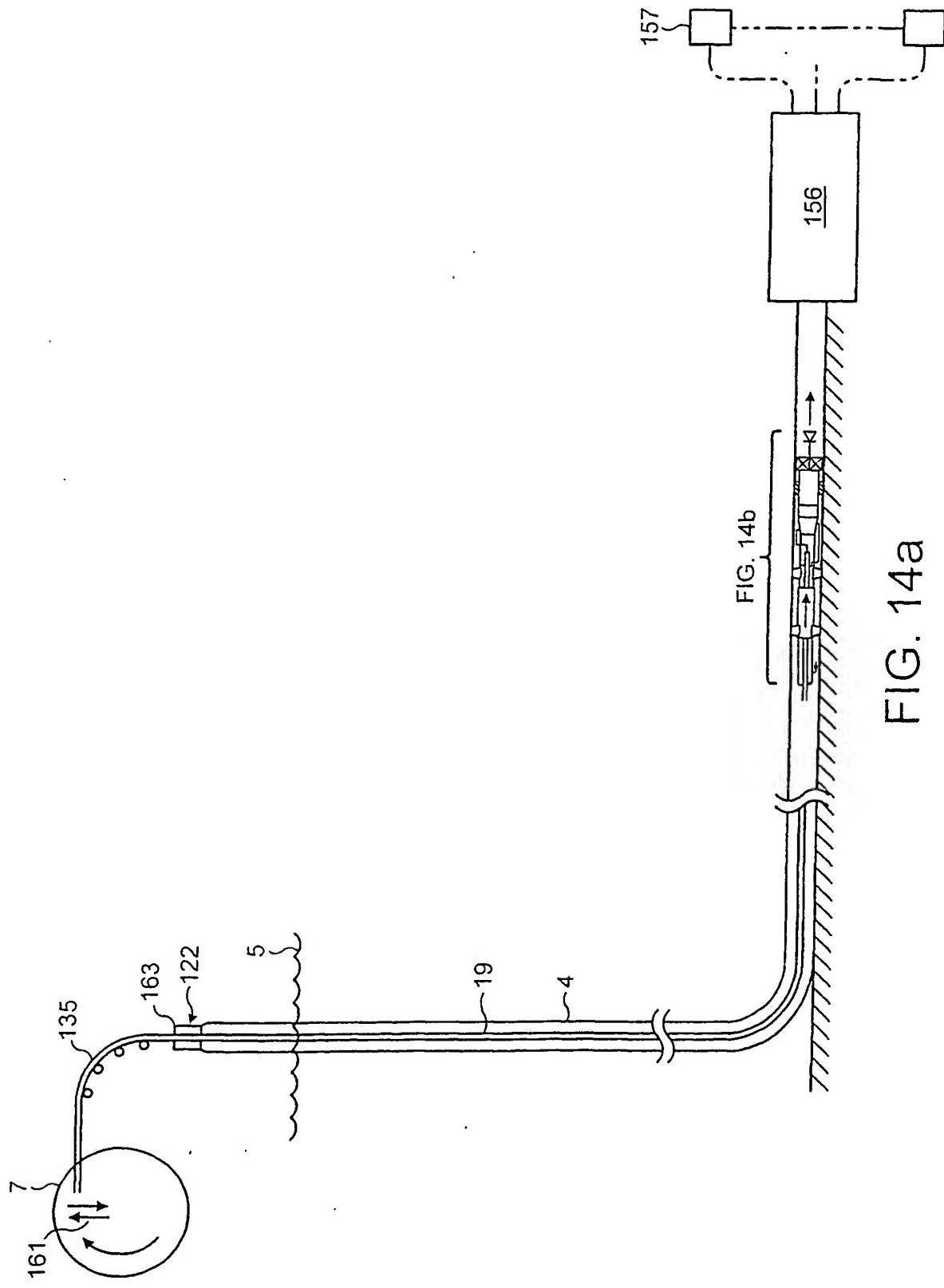


FIG. 14a

FIG. 14b

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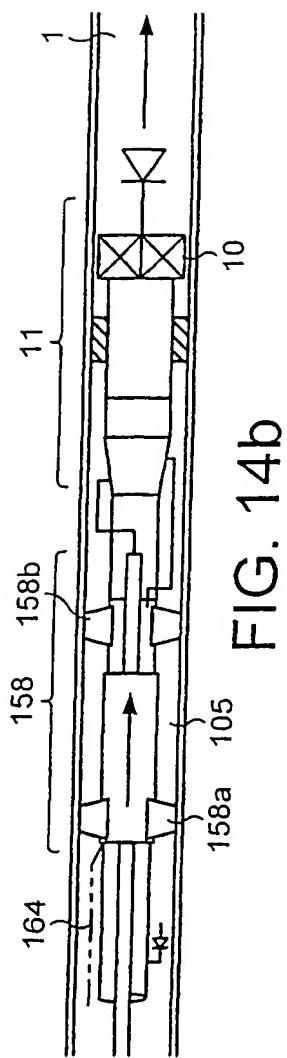


FIG. 14b

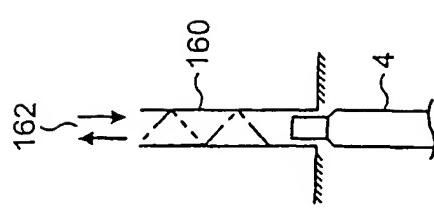


FIG. 14c

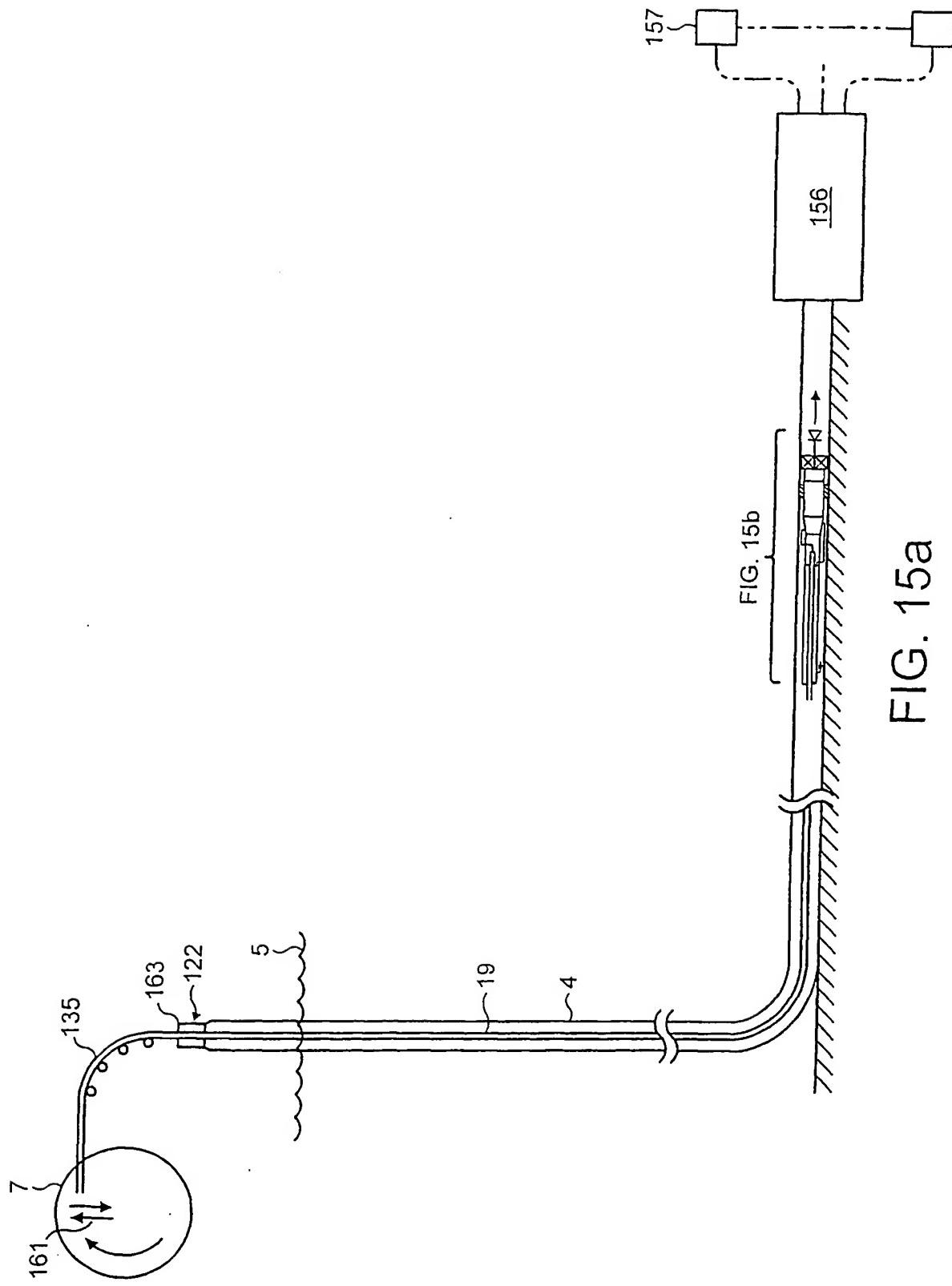


FIG. 15a

FIG. 15b

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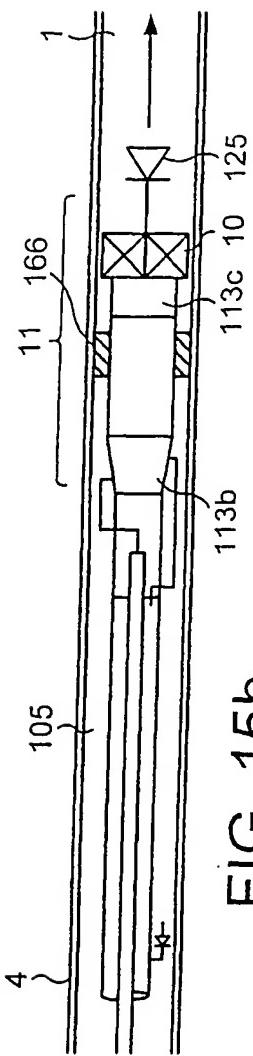


FIG. 15b

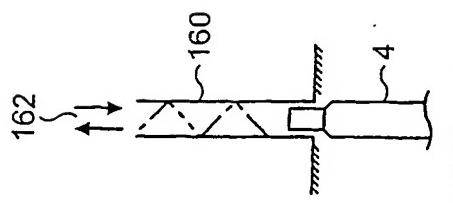


FIG. 15c

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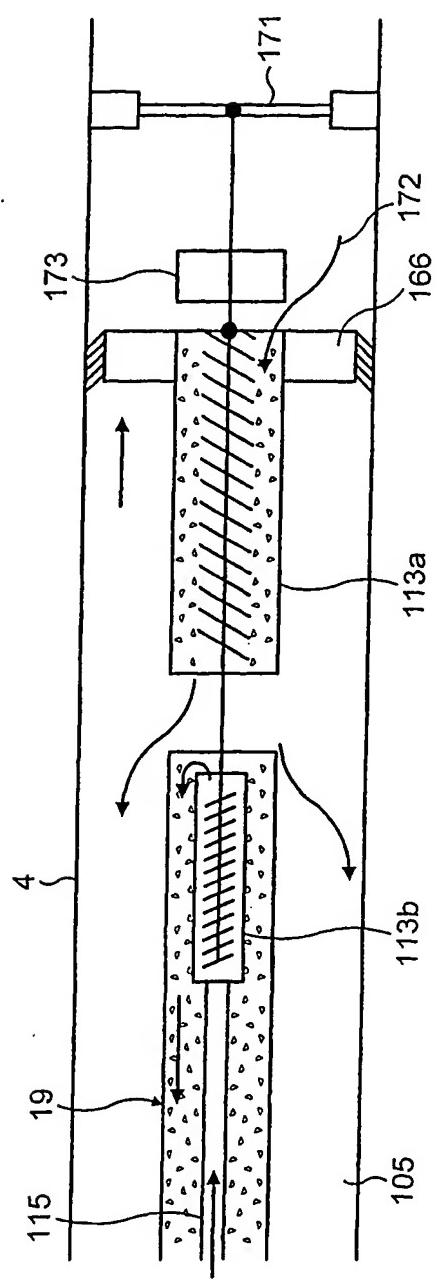


FIG. 16a

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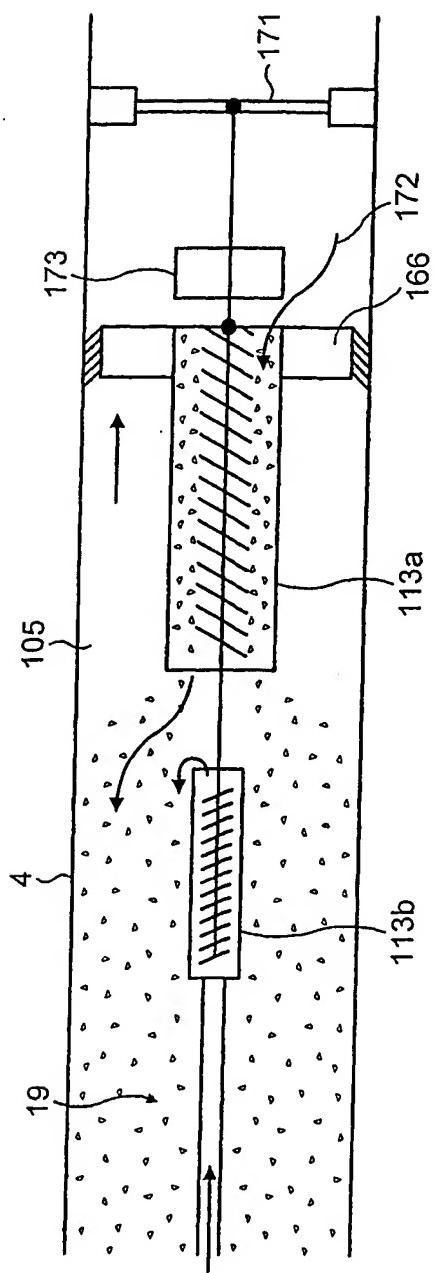


FIG. 16b

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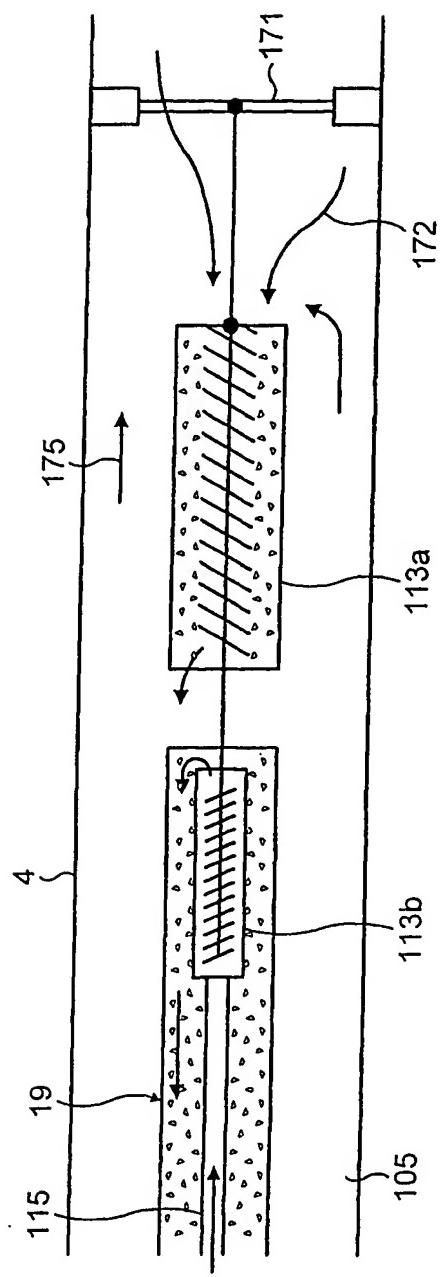


FIG. 16c

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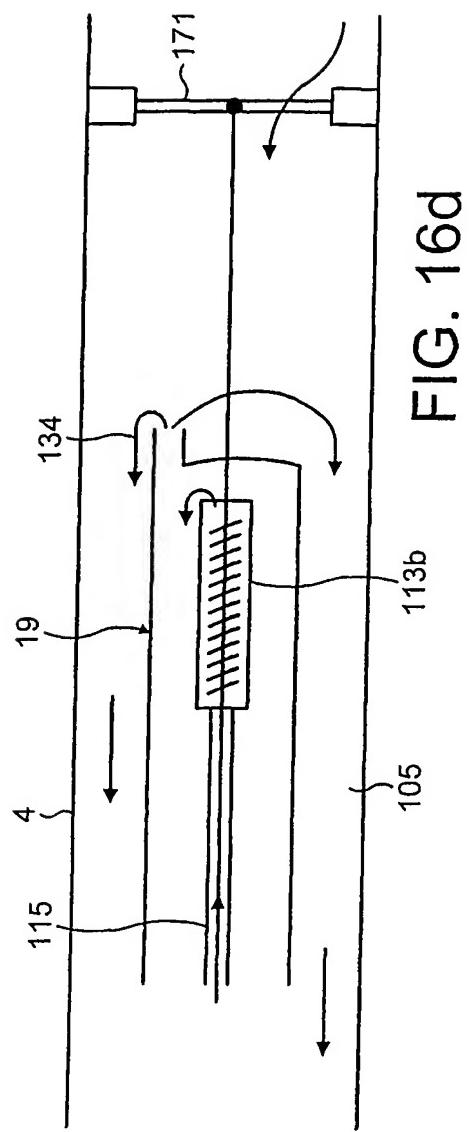


FIG. 16d

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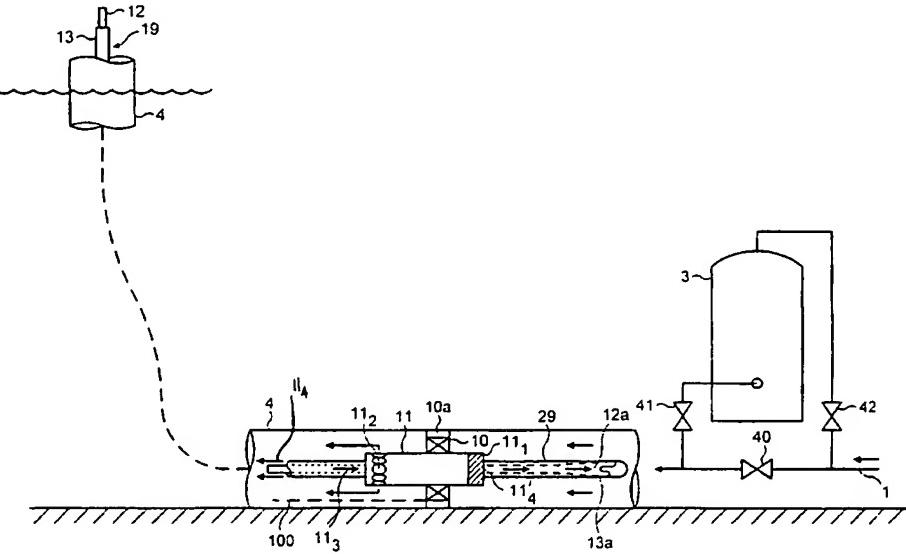
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(54) Title: RISER WITH RETRIEVABLE INTERNAL SERVICES



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(57) Abstract: Systems are described for raising production fluid from a source (1) on the seabed comprising a riser (4) having a first, lower, end for connection to the source; a top end support for supporting the riser at or in the vicinity of the sea surface; and an operating device (11) mounted inside the riser (4) for displacement within the riser so that the pump is accessible to an operator for replacement or repair. The operating device (11) may be displaced on a pipe (12) which extends within the riser (4) and to a lower end of which the device (11) is attached. The device (11) may be *inter alia* an electric pump, a hydraulic pump, a gas injector, a heater or a cleaning device.



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# INTERNATIONAL SEARCH REPORT

International Application No  
PCT/EP 01/03405

<b>A. CLASSIFICATION OF SUBJECT MATTER</b>					
IPC 7 E21B43/12 E21B43/01 E21B37/00 E21B36/00 E21B19/22 E21B17/01 E21B23/08 E21B43/36					
According to International Patent Classification (IPC) or to both national classification and IPC					
<b>B. FIELDS SEARCHED</b>					
Minimum documentation searched (classification system followed by classification symbols)					
IPC 7 E21B					
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched					
Electronic data base consulted during the international search (name of data base and, where practical, search terms used)					
EPO-Internal, PAJ, WPI Data					
<b>C. DOCUMENTS CONSIDERED TO BE RELEVANT</b>					
Category *	Citation of document, with indication, where appropriate, of the relevant passages				Relevant to claim No.
X	GB 2 280 460 A (ALTRA CONSULTANTS LIMITED ; YTHAN ENGINEERING LIMITED (GB)) 1 February 1995 (1995-02-01) page 7, line 6 - line 34; figure 7				1-3, 12, 33-39
Y					18-20, 40-42, 48, 49
X	WO 98 28519 A (SUDOL TADEUS) 2 July 1998 (1998-07-02)  page 3, line 27 - line 29; figure 1 page 6, line 8 - line 20 page 8, line 22 - line 27				1-3, 5-10, 12, 13, 35-39
Y					11, 22-24
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<input checked="" type="checkbox"/> Further documents are listed in the continuation of box C.			<input checked="" type="checkbox"/> Patent family members are listed in annex.		
* Special categories of cited documents :					
*A* document defining the general state of the art which is not considered to be of particular relevance			*T* later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention		
*E* earlier document but published on or after the international filing date			*X* document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone		
*L* document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)			*Y* document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.		
*O* document referring to an oral disclosure, use, exhibition or other means			*&* document member of the same patent family		
*P* document published prior to the international filing date but later than the priority date claimed					
Date of the actual completion of the international search			Date of mailing of the international search report		
7 November 2001			16. 11. 2001		
Name and mailing address of the ISA			Authorized officer		
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl Fax: (+31-70) 340-3016			Dantinne, P		

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Int. Application No  
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C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GB 2 340 155 A (CAMCO INC) 16 February 2000 (2000-02-16)  page 1, line 22 - line 23; figure 1 page 5, line 6 - line 12 ---	1-4, 15-17, 35-39
X	US 4 125 162 A (GROVES SR DAVID L ET AL) 14 November 1978 (1978-11-14)  column 2, line 3 - line 37; figure 1 column 4, line 57 -column 5, line 6 column 9, line 5 - line 12 ---	1-3,5, 10,13, 25, 33-36, 53,54
Y	US 5 671 811 A (HEAD PHILIP) 30 September 1997 (1997-09-30) column 1, line 25 - line 42; figure 7 ---	26,27, 55,56
X	US 5 287 923 A (CORNETTE H MITCHELL ET AL) 22 February 1994 (1994-02-22) column 7, line 9 - line 14; figure 1 ---	1-3,13, 33,34
Y	US 4 625 798 A (BAYH III RUSSELL I) 2 December 1986 (1986-12-02) column 1, line 32 - line 33; figure 1 column 3, line 45 - line 55 ---	22-24
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P,X	WO 00 43632 A (HEADWORTH COLIN STUART) 27 July 2000 (2000-07-27) page 11, line 15 - line 17; claim 36; figure 13 ---	1-3,5, 13,33,34
A	US 5 967 699 A (KNAPP KENNETH M) 19 October 1999 (1999-10-19) column 5, line 65 -column 6, line 62; figure 2 ---	1,35
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Y	---	18-20, 40,42, 46-50
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A	EP 0 909 873 A (PETROLEO BRASILEIRO SA) 21 April 1999 (1999-04-21) page 4, line 38 - line 40 page 5, line 14 - line 17 ---	18,40,45
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A	WO 97 47855 A (PETROLEO BRASILEIRO SA ;LIMA PAULO CESAR RIBEIRO (GB)) 18 December 1997 (1997-12-18) page 8, line 4 - line 13; figure 2 ---	18,40,45
Y	US 6 032 737 A (BRADY JERRY L ET AL) 7 March 2000 (2000-03-07) column 5, line 6 - line 12; figure 2 column 5, line 21 - line 35 column 8, line 16 - line 22 ---	21,44, 51,52
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A	GB 2 133 446 A (TREASURE OFFSHORE PRODUCTION S) 25 July 1984 (1984-07-25) claims 1,2; figure 1 ---	21,44, 51,52
A	US 5 474 601 A (CHOI MICHAEL S) 12 December 1995 (1995-12-12) cited in the application column 3, line 8 - line 31; figure 1 ---	21,44, 51,52
Y	US 4 378 051 A (CHOLET HENRI ET AL) 29 March 1983 (1983-03-29)  claims 1,2; figure 1 ---	26,27, 29,30, 55,56,58
A	US 3 346 045 A (R.P. KNAPP) 10 October 1967 (1967-10-10) claim 1; figure 1 ---	1,25,53, 54
X	WO 98 06927 A (ASTEC DEV LTD ;SIMPSON NEIL ANDREW ABERCROMBI (GB)) 19 February 1998 (1998-02-19) page 1, line 8 - line 12; figures 3,7 page 16, line 12 - line 25 ---	1-3,5, 28,57
Y	----- -/-	29,30, 32,58

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C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5 033 545 A (SUDOL TAD A) 23 July 1991 (1991-07-23) column 5, line 60 -column 6, line 3; figure 6	1-3,5-9, 13,35-39
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## INTERNATIONAL SEARCH REPORT

International application No.  
PCT/EP 01/03405

### Box I Observations where certain claims were found unsearchable (Continuation of item 1 of first sheet)

This International Search Report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1.  Claims Nos.: because they relate to subject matter not required to be searched by this Authority, namely:
  
2.  Claims Nos.: because they relate to parts of the International Application that do not comply with the prescribed requirements to such an extent that no meaningful International Search can be carried out, specifically:
  
3.  Claims Nos.: because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

### Box II Observations where unity of invention is lacking (Continuation of item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

see additional sheet

1.  As all required additional search fees were timely paid by the applicant, this International Search Report covers all searchable claims.
  
2.  As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.
  
3.  As only some of the required additional search fees were timely paid by the applicant, this International Search Report covers only those claims for which fees were paid, specifically claims Nos.:
  
4.  No required additional search fees were timely paid by the applicant. Consequently, this International Search Report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

#### Remark on Protest

- The additional search fees were accompanied by the applicant's protest.
- No protest accompanied the payment of additional search fees.

FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. Claims: 1-17,22-24,33-39

System and method to install retrievably an operating device inside a riser to raise production fluid to avoid to have time-consuming repair or replacement

2. Claims: 18-20,40-43,45-50

System and method to inhibit formation of solid hydrates in a production fluid during interrupted or shutdown conditions by expelling production fluid and pressure reduction

3. Claims: 21,44,51,52

Apparatus and method for separating production fluid prior to lift the liquid-rich underflow with a pump

4. Claims: 25-27,53-56

A traction device on a pipe to move inside an extended near-horizontal conduit

5. Claims: 28-32,57-59

System to clean the inside of a riser using a pipe, a motor and a rotary cleaning device

# INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

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Information on patent family members

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